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Proposed Outer Continental Shelf Orders Governing Oil and Gas Lease Operations in the Arctic; Environmental Assessment

DEPARTMENT OF THE INTERIOR

Geological Survey

Proposed Outer Continental Shelf Orders Governing Oil and Gas Lease Operations in the Arctic; Environmental Assessment

AGENCY: U.S. Geological Survey, Department of the Interior.

ACTION: Environmental Assessment for the proposed Arctic Outer Continental Shelf Orders.

SUMMARY: the U.S. Geological Survey (USGS) prepared this Environmental Assessment (EA) to document the potential environmental effects of issuing the proposed Arctic Outer Continental Shelf (OCS) Orders. The EA was prepared in accordance with the regulations implementing the National Environmental Policy Act (40 CFR Parts 1500.1508). Comments on the EA will be considered by the USGS before a decision is made to issue final Arctic OCS Orders.

DATE: Comments must be received by 4:30 p.m., e.s.t., January 19, 1981.

ADDRESS: Responses should identify the subject matter and be directed to the Deputy Division Chief—Offshore Minerals Regulation, Conservation Division—Attention: Lloyd Tracey, Branch of Offshore Rules and Procedures, U.S. Geological Survey, National Center, Mail Stop 640, Reston, Virginia 22092.

FOR FURTHER INFORMATION CONTACT: Rishi Tyagi, U.S. Geological Survey, Alaska OCS Region, P.O. Box 259, Anchorage, Alaska 99510, (907) 271–4348; or Ray Beittel, U.S. Geological Survey, National Center, Mail Stop 640, Reston, Virginia 22092, (703) 860–7567.

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Dated: December 15, 1980.

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Environmental Assessment for the Proposed Arctic OCS Orders

Table of Contents

I. Introduction
- A. The Proposed Action: To Adopt Operating Orders for the Arctic Outer Continental Shelf (OCS) Area
- B. Scope of the Environmental Assessment
- C. Summary of Oil and Gas Activities in the Beaufort Sea
- D. Summary of Potential Environmental Effects of Exploration Activities in the Beaufort Sea

II. Environmental Effects of the Proposed Arctic OCS Orders
- A. Proposed Arctic OCS Order No. 1. Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects
- B. Proposed Arctic OCS Order No. 2. Drilling Operation.
- C. Proposed Arctic OCS Order No. 3. Plugging and Abandonment of Wells
- D. Proposed Arctic OCS Order No. 4. Determination of Well Producibility
- E. Proposed Arctic OCS Order No. 5. Production Safety Systems
- F. Proposed Arctic OCS Order No. 7. Pollution Prevention and Control
- G. Proposed Arctic OCS Order No. 8. Platforms and Structures
- H. Proposed Arctic OCS Order No. 12. Public Inspection of Records

III. Alternatives to the Proposal
- A. No Arctic OCS Orders
- B. OCS Orders Less Stringent Than the Proposed Arctic OCS Orders
  1. Alternative OCS Order No. 1
  2. Alternative OCS Order No. 2
  3. Alternative OCS Order No. 3
  4. Alternative OCS Order No. 4
  5. Alternative OCS Order No. 5
  6. Alternative OCS Order No. 7
  7. Alternative OCS Order No. 8
  8. Alternative OCS Order No. 12
- C. OCS Orders More Stringent Than the Proposed Arctic OCS Orders
  1. First Part of the Alternative
  2. Second Part of the Alternative
  3. Third Part of the Alternative
  4. Fourth Part of the Alternative
  5. Fifth Part of the Alternative

Appendix. The Proposed Arctic OCS Orders

I. Introduction

A. The Proposed Action: To Adopt Operating Orders for the Arctic Outer Continental Shelf (OCS) Area

The U.S. Geological Survey's (USGS) proposed Arctic OCS Orders for offshore oil and gas exploration, development and production operations are a special type of agency regulation applying to a special area of America's OCS. They would govern many oil and gas exploration, development, and production activities conducted offshore from Alaska, at locations on the OCS that are north of the Arctic Circle. The Arctic OCS is bordered on the east by the Canadian section of the Beaufort Sea, on the west by the Soviet section of the Chukchi Sea, and on the south by the Seward Peninsula. The Arctic, the coldest area offshore of the United States, poses unusual hazards to OCS oil and gas exploration, development, and production activities. However, when conducted properly, these activities will not cause significant harm to the Arctic marine, coastal, or human environments.

The proposed Arctic OCS Orders are designed to assure that no unacceptable environmental risks are taken by those persons who explore for and produce oil and gas on the Arctic OCS. The need for OCS Orders to govern activities on the Arctic OCS is clear. The success of OCS operating Orders in other OCS areas was one of the factors which persuaded Interior Department Secretary Cecil Andrus that the Beaufort Sea OCS could be explored and developed safely.

The proposed Arctic OCS Orders are created under the authority given to the Secretary by the Outer Continental Shelf Lands Act, as amended. OCS Orders supplement the Department's general regulations that govern OCS oil and gas operations, found in Part 250 of Title 30, Code of Federal Regulations (CFR), by imposing special requirements on operations in the Arctic OCS area. In this respect they are similar to some of the special stipulations found in the Federal OCS leases issued as a result of the Beaufort Sea lease sale. A lessee must comply with the special lease stipulations, the OCS Orders, the regulations, and the Act as a apart of his obligations under the OCS oil and gas lease. The lessee who violates any of these types of law is subject to civil and/or criminal penalties. He may also lose his lease.

OCS Orders are in effect in all other Federal OCS areas where OCS oil and gas leases have been issued. In most respects the proposed Arcitc OCS Orders resemble these other OCS Orders. Indeed, the OCS Orders for all areas are virtually identical in format.

- Order No. 1–Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects
- Order No. 2–Drilling Operations
- Order No. 3–Plugging and Abandonment of Wells
- Order No. 4–Determination of Well Producibility
- Order No. 5–Production Safety Systems
- Order No. 6–Well Completions and Workover Operations [called "Procedure for Completion of Oil and Gas Well" in some areas.]
- Order No. 7–Pollution Prevention and Control
- Order No. 8–Platforms and Structures
- Order No. 9–Oil and Gas Pipelines [Gulf of Mexico and Pacific]
- Order No. 10–(Reserved) ["Sulphur Drilling Procedures" in the Gulf of Mexico; "Drilling of Twin Core Holes" in Pacific]
- Order No. 11–Oil and Gas Production Rates, Prevention of Waste, and Protection of Correlative Rights [Gulf of Mexico and Pacific]
- Order No. 12–Public Inspection of Records
- Order No. 13–Production Measurement and Commingling [Gulf of Mexico]

The proposed Arctic OCS Orders would, however, impose requirements not found in the Orders for other areas. The differences fall into five categories. The first is planning. Beaufort Sea lessees will have to present their plans for

responding to certain types of emergencies to the USGS. lessees will also have to submit "Critical Operations and Curtailment Plans" that are more detailed than those required for the highly developed ("mature") areas of the Gulf of Mexico. The second category includes those measures lessees must take to ensure that their operations are carried out in a way that keeps the permafrost from melting. The third category includes those measures lessees must take to insure that platforms, equipment, and materials which the lessee proposes to use are designed to work under Arctic conditions. The fourth and fifth categories are single measures. One requires the lessee to keep closer track of where the bottom of the well bore is. The other requires the lessee who drills from an artificial island to build an impervious berm to contain all liquid hydrocarbons that are expected to be present on the artificial island. Each of these differences will be explained in detail in Part II. A complete text of the proposed Arctic OCS Orders is included in the Appendix.

B. Scope of the Environmental Assessment

During the course of the litigation brought against the Department of the Interior by the North Slope Borough regarding the Beaufort Sea Lease Sale, the Chief, Conservation Division, USGS, presented an affidavit to the U.S. District Court regarding the proposed Arctic OCS Orders. One of the statements in that affidavit committed the GS to conducting an environmental analysis of the proposed Arctic OCS Orders before they are published in final form. This EA documents that environmental analysis. It includes consideration of the differences between the proposed Arctic OCS Orders and OCS Orders in effect for other OCS areas. It also includes consideration of appropriate alternatives as specified in the affidavit. Comments received as a result of the publication of this analysis will be considered before final Arctic OCS Orders are published and made effective. This assessment also discusses how oil and gas operations are to be conducted in the Beaufort Sea lease sale area and how the Arctic OCS Orders will provide guidance on the manner in which lessees are to conduct some of these activities.

The Federal/State Joint Beaufort Sea Oil and Gas Lease Sale, Sale BF, which was held in December 1979, represents the first part of the Arctic OCS area to be leased. Additional sales currently proposed in the Secretary's 5-year leasing schedule are: Beaufort Sea, Sale No. 71, in February 1983; Chukchi Sea, Sale No. 85 in February 1985; and Hope Basin, Sale No. 86, in May 1985. Because the effectiveness of the proposed Orders will be tested first in the Beaufort Sea, and since the most complete environmental data has been gathered in the area of Sale BF, our discussion is limited to the effects of oil and gas operations in the Beaufort Sea area.

C. Summary of Oil and Gas Activities in the Beaufort Sea

OCS Orders are only part of the regulatory scheme that will govern oil and gas operations on the Beaufort Sea OCS. Some activities are unaffected by the OCS Orders themselves. This is an important point to remember, because this assessment is limited to the provisions of proposed Arctic OCS Orders and selected alternatives and their effects on the environment. Perhaps the easiest way to explain this point is to summarize those activities that have occurred and those activities that the Department expects to occur in the Sale BF lease area.

Before offering OCS oil and gas leases in the Beaufort Sea area, the Bureau of Land Management (BLM) prepared an Environmental Impact Statement (EIS). That EIS was recently supplemented. The EIS and its supplement document the extensive review of the potential environmental effects of oil and gas activities on the area. Based on the information and analysis contained in the EIS, the Secretary of the Interior imposes several special restrictions on the lessess in the form of lease stipulations included in oil and gas leases issued for the Beaufort Sea OCS. A few of the 12 special Federal lease stipulations were imposed to protect the Government's proprietary interests, but most were designed to assure adequate protection of the Arctic environment.[1] These stipulations are discussed later on this summary.

With the lifting of the U.S. District Court's injunction in July 1980, the Department began to issue 10-year leases to the successful bidders. Then the lessees began to carry out preliminary geophysical surveys and, on certain tracts, the environmental surveys required by Federal Lease Stipulation Number 7 (See 44 FR 64762). If these surveys reveal sites of historic or archaeological significance, lessees must notify the USGS Deputy Conservation Manager. The Manager will instruct the lessee as to the steps that must be taken to protect such sites, as required by Federal Lease Stipulation Number 1.

As this document is being written, a number of lessees are conducting these preliminary surveys.

After completing and evaluating these preliminary surveys, the lessees will prepare Exploration Plans. These plans, required by 43 U.S.C. 1340, must be submitted to the USGS for approval. The Exploration Plan must be accompanied by an Environmental Report that addresses the potential site specific environmental effects of activities described in the plan.

A lessee cannot conduct any other activities related to exploration for oil and gas until the Exploration Plan is approved. Departmental regulations prescribe what information lessees must include in their Exploration Plans. These plans must include descriptions of where and when the lessee will drill and conduct surveys, descriptions of the equipment to be used, safety and pollution-prevention features of the equipment, and geologic maps of the sites to be drilled. It is in the preparation of an Exploration Plan that the proposed Arctic OCS Orderswill first affect oil and gas activities in the Beaufort Sea. As explained in Part II, the proposed Arctic OCS Orders require lessees to submit information not required in other OCS areas. This information includes a description of how the lessee will deal with four types of emergencies, and evidence that the lessee's drilling unit can withstand Arctic conditions.

Federal Lease Stipulation No. 2 requires lessees to include still further information in their Exploration Plans. Lessees must submit environmental training and briefing programs for their personnel and their contractor's personnel (See 44 FR 64761). Lessees have 4 years before they must file the initial Exploration Plan or a statement of exploration intentions for a lease. The GS will prepare an EA for each Exploration Plan before approving or disapproving it.

Exploration Plan approval is one of four such approvals a lessee must receive before drilling operations may begin. Drilling in the Beaufort Sea will probably be done from artifical islands made of gravel, silt, or possibly ice. Before constructing one of these islands, a lessee must obtain a permit from the Corps of Engineers, as required by Section 10 of the Rivers and Harbors Act of 1899 and Section 4(e) of the OCS Lands Act. Based on its actions relating to permits issued for activities on State oil and gas leases in the sale area, it is expected the Corps will prepare an EA

[1] The United States and the State of Alaska dispute ownership over part of the area leased. Because of this dispute, the area was leased jointly by the two Governments. The Federal and State environmental stipulations are nearly identical. See 44 FR 64748–770 (Nov. 7, 1979).

for artificial island permit applications submitted for OCS oil and gas leases.

Lessees must also have the design, construction, and installation of each artificial island approved by the USGS in accordance with the OCS Platform Verification Program. This 3-part program, required by proposed Arctic OCS Order No. 8, provides for verification of what engineers call the "structural integrity" of the islands.[2] Additionally, in the November Notice of Sale, the Department announced a supplementary restriction on drilling from manmade islands located seaward of the barrier islands. Any artificial island that is built seaward of the barrier islands in water deeper than 13 (43 ft.) meters must be built as a test platform and left in place for two winter seasons before drilling operations are conducted from the island. After this period has passed, the USGS will determine whether the platform will be accepted for its durability. Finally, lessees must obtain USGS approval of a permit to drill for each well. Certain parts of the proposed Arctic OCS Orders apply to this application, as explained in Part II. The Department will not prepare EA's for these drilling permits or for the approval of OCS drilling platforms under proposed Arctic OCS Order No. 8 since these activities will have been addressed in the EA for an Exploration Plan or a Development and Production Plan.

During the first 2 years after the Beaufort Sea OCS leases are issued (i.e., August 1980 through July 1982), lessees may drill only during the months of November through March (See Federal Lease Stipulation No. 8.). This restriction also applies to other activities in the wellbore, such as pressure testing and sampling of fluids in a potential reservoir of oil and gas. The purpose of this restriction is to prevent any disturbance to the endangered bowhead and gray whales, which swim through the lease area during the summer months. By the end of the 2-year period, the Department expects that the National Marine Fisheries Service will have issued its biological opinion on whether oil and gas operations in the Beaufort Sea will jeopardize the continued existence of these endangered species. By the summer of 1982, the Department is expected to decide if continued seasonal drilling restrictions are necessary to protect the whales.

Once drilling is begun, several other provisions of the proposed Arctic OCS Orders would take effect. Most of these are found in proposed Arctic OCS Order No. 2. This long, detailed Order regulates the "casing" (a number of "strings" of special pipe lowered into the well during the drilling process to support the sides of the well, to prevent communication between wellbore formation fluids, and to facilitate well control), the "cementing" (the process of bonding the casing to the surrounding rock or another larger diameter string of casing), "blowout preventers" (a device placed on the surface end of casing which is designed to prevent an uncontrolled flow of oil or gas out of the casing), and the "mud program" (the characteristics, testing, and proper use of the special fluid (i.e., mud) which is mixed at the surface, pumped down the well through the drillpipe and out ports in the drillbit, and up to the surface in the annulus between the drillpipe and the casing). These activities, and others addressed by proposed arctic OCS Order No. 2, are discussed in detail in Part II. Other provisions that normally come into play at this time are found in proposed Arctic OCS Order No. 7, which governs pollution prevention and control activities. These, too, are discussed later.[3]

The Beaufort Sea OCS leases were issued for a primary term of 10 years. This means that these leases will expire in 1990, 10 years after their effective date, unless one or a combination of the following happens:

1. The lessee is actually producing oil or gas;
2. The lessee is still drilling (with lapses in drilling operations of no greater than 90 days);
3. The lessee is performing maintenance on a well (called "reworking" or "workover"); or
4. The lease term has been extended by a USGS or Departmental order suspending operations on the lease.

Within these 10 years, the Department expects the lessees to drill several wells on their leases. By using special "directional drilling" tools, lesses will be able to drill a number of exploratory wells from a single artificial island. Some of these wells may not find oil or gas, and some may find oil or gas in amounts in sufficient to justify development and production, at some point, the lessee will obtain USGS approval to "plug and abandon" these wells, that is, to place cement "plugs" at strategic locations in the wellbore and remove the blowout preventers and recoverable portions of the casing. The requirements of proposed Arctic Order No. 3 will come into play at that point. Proposed OCS Order No. 3 (explained more fully in Part II) requires lessees to obtain abandonment plan approval from the USGS before abandoning the well. This proposed Order sets minimum standards for lessees to follow when setting cement plugs in the well to prevent oil, gas, or other fluids from flowing up or down the wellbore or into the marine environment.

When a lessee ultimnately abandons operations on an artificial island, nothing in the operating regulations or proposed Arctic OCS Orders requires him to disassemble his rig or remove the artificial island. However, the provisions of Federal leases and Federal lease Stipulations numbers 1 and 3 require both of these on certain tracts: Those between the mainland and the barrier islands, and those containing sites of archaeological or historic significance (See 44 FR 64761, November 7, 1979).

The chances are good, however, that some lessees will find valuable reservoirs of oil and/or gas. After the discovery of one or more such reservoirs, the lessee may drill "delineation wells"—wells that allow him to delineate the extent of the oil and gas in the reservoir. Each delineation well must be described in an approved Exploration Plan and also requires a permit to drill from the USGS.

One exploratory drilling is completed, and before lessees can drill development wells, the lessee must submit a Development and Production Plan for USGS approval. Development and Production Plans must include the information required by 30 CFR 250.34–2(a), including a description of safeguards to prevent harm to persons, property, and the environment. The Development and Production Plan must also be accompanied by an Environmental Report that describes site specific environment impacts of the activities proposed in the plan. The USGS will prepare an EA for each Development and Production Plan before approving, requiring modification, or disapproving it. At least once, in each OCS area or region other than the western Gulf of Mexico, the USGA will prepare an EIS for a proposed Development and Production Plan. As with the Exploration Plan, the lessee cannot drill any development wells or produce oil or gas until he obtains USGS approval of a Development and Production Plan. And

[2] See 44 FR 64767 (November 7, 1979). See also the USGS document, "Requirements for Verifying the Structural Integrity of OCS Platforms."

[3] Federal Lease Stipulations Nos. 4 and 6 also restrict discharges and partly supersede proposed Arctic OCS Order No. 7 in the area of Sale BF. Lessees must also obtain NPDES permits from the Environmental Protection Agency before discharging drilling fluids, drill cuttings, brine from the well, produced sands, drainage from the deck of the drilling rig, human and domestic wastes, and other kinds of wastewater.

as with the Exploration Plan, certain parts of the proposed Arctic OCS Orders provide guidance regarding the content of a Development and Production Plan. These are explained in Part II.

A lessee may have to modify an artificial island used for exploration before initiating development and production activities, such as installing production equipment. If the proposed modification is major, it must be approved by the GS in accordance with proposed OCS Order No.'s Platform Verification Program. The lessee must also obtain USGS approval before installing production equipment or drilling any production well described in the approved Development and Production Plan. When production activities begin, proposed Arctic OCS Order No. 5 will come into play.[4] OCS Order No. 5 regulates the safety systems used in the production of oil and gas. This proposed Order sets standards for the types of equipment to be used, requires the lessee to provide evidence that the equipment can operate normally in Arctic conditions, and requires the lessee to inspect the equipment regularly. In certain situations, the lessee must also get; USGS approval before installing equipment. Proposed Arctic OCS Order No. 5 will be explained in greater detail in Part II.

At the time of this writing, actual production of oil or gas is still a few years away. Therefore, the summary of production activities cannot be exact. A significant production activitiy will be transporting the oil and gas to shore. Federal Lease Stipulation No. 5 favors the use of pipelines over barges, but these methods of transportation will be studied further before the State and Federal Governments agree to a lessee's a specific proposal to transport oil and/or gas from a lease area. Proposed Arctic OCS Order No. 9, which will provide guidance with respect to design and contruction of oil and gas pipelines, is still under development.

Perhaps 10 to 20 years after production begins, when the natural pressure in the oil and gas reservoirs has dropped significantly, a lessee will consider artifical methods of bringing the oil and gas out of the ground. These are the so-called "enhanced recovery" methods. Ultimately, the cost of recovering oil or gas will reach a point where it is greater than the market value. At that time the lessee will plug and abandon the wells, in accordance with the requirements of Arctic OCS Order No. 3 then in effect.

[4] Actually, several proposed Orders will begin to apply. But some of these have not yet been drafted for the Arctic. These are OCS Orders Nos. 6, 9, 11, 13, and 14.

D. Summary of Potential Environmental Effects of Exploration activities in the Beaufort Sea

There are several types of potential environmental effects associated with conducting oil and gas exploration activities on federal OCS leases issued in the Beaufort Sea. These potential effects are described in detail in the *Beaufort Sea Final EIS* prepared by the BLM in 1979. A brief summary of the potential effects related to exploration activities is provided below. The summary will serve to orient the reader as to the general scope of potential environmental impacts related to hydrocarbon exploration, and identify for the reader the potential effects that the proposed Arctic OCS Orders were developed to address. It should be understood that the following discussion provides a general outline of the potential effects of Beaufort Sea OCS exploration activities and *not* the effects of the proposal to issue operating Orders for the Arctic OCS. An analysis of the potential environmental impacts of the proposed Arctic OCS Orders is presented in Part II of this assessment.

The potential environmental effects related to oil and gas exploration activities in the Beaufort Sea are generally associated with (1) construction of structures (e.g., gravel islands) from which exploration activities will be conducted, (2) discharges resulting from drilling operations, including possible oil spills, and (3) transportation of persons and supplies to and from the drilling site.

1. *Structures.* The most commonly used exploratory platform on the Beaufort OCS is expected to be an artificial island grounded to the sea floor. Several designs have been used successfully in comparable areas of the Canadian Beaufort Sea. It is likely that islands on the Alaskan Beaufort OCS will be constructed of gravel. The BLM estimates that a typical gravel island will be approximately 1 hectare (2 acres) in surface area and will require between 27,000 m^3 (950,000 $ft.^3$) and 1,000,000 m^3 (35,000,000 $ft.^3$) of gravel to construct, depending on water depth at the drill site and design characteristics of the island.

The potential environmental effects of gravel island construction are associated primarily with dredge and fill activities. The largest and most widely distributed gravel resource located within the sale area is found 3 to 10 meters (11 to 33 ft.) beneath the sea floor in the form of a pleistocene (deposited between 10 thousand and 2 million years ago) gravel sheet. Assuming that the gravel needed for construction is mined by dredging during the open water season, the following impacts are likely to result:

(a) Temporary (on the order of decades) depressions will be created in the sea floor;

(b) The existing benthic (sea bottom) environment in the area of dredging will be temporarily disrupted or destroyed; and

(c) Water column turbidity will increase as a result of temporary resuspension of bottom sediments causing a disturbance to some plant and animal species that encounter the turbidity plume.

Deposition of dredged material at the construction site during the open water season will probably generate the following effects at or near the site:

(a) Portions of the existing benthic community will be buried and destroyed; and

(b) Water column turbidity will increase resulting in a disturbance of some plant and animal species that encounter the turbidity plume. The intensity of the plume may vary greatly depending on the method of gravel deposition (clamshelling or barge dumping).

The nature and extent of the biological disturbance related to open water dredge and fill activities will depend on the type of species affected, the season, and probably the life stage of individual species. The impacts of these dredge and fill activities would be minimized, however, if they are conducted during winter through fast ice.

Other potential effects associated with gravel islands include: (a) Low frequency, underwater noise generated during construction activities. This may interfere with communication among and echolocation (determination of an animal's position by detecting the reflection of sounds made by the animal) of the whales that migrate through the area. In addition, there is some evidence that certain seal species are particularly sensitive to human disturbance. Noises associated with construction may alter the living habits of some seals to the extent that a population decline could result; and

(b) Artificial islands may act as physical impediments to fish and mammals, particularly the endangered bowhead whale, that migrate through the area.

2. *Drilling Activities.* It is anticipated that exploratory drilling activities will be conducted from gravel island platforms using land-type drilling rigs

and essentially the same technology and techniques used in the Arctic to drill an onshore well. Assuming that the typical exploratory well will be drilled to a depth of 15,000 feet, the BLM lease sale EIS estimates that approximately 4,500 barrels of drilling muds will be used. For wells drilled in water depths of 10 meters (33 ft.) or greater, these muds will probably be discharged directly into the marine environment. In water depths of less than 10 meters (33 ft.), the USGS District Supervisor will approve, on a case-by-case basis, the method for disposal of the drill muds. Approximately 700 cubic yards of drill cuttings will be generated as each well is drilled.

The potential, primary environmental effects associated with routine discharges of drill muds and cuttings into the marine environment are:

(a) Burial and smothering of benthic communities by drill cuttings and mud within at least a 17-meter (56 ft.) radius of the discharge point;

(b) Temporary increases in water turbidity levels resulting in a disturbance to some plants and animals that encounter the plume, and decreases in the penetration of light into the water column. The areal extent of the turbidity plume will depend primarily on water depth and water circulation patterns near the drill site; and

(c) Minor changes in the chemical composition of sediments surrounding the drill site.

It is conceivable that at some time during drilling operations control over the fluid pressures in the well may be lost. In the event that this occurs and emergency procedures fail to maintain control of the well, a blowout may result. This may release a quantity of oil and/or gas into the environment. A recent study completed by the USGS (USGS Open-File Report 80–101) indicates that during the 8-year period, 1971–1978, one blowout occurred for every 250 wells drilled on the Gulf of Mexico OCS. The BLM estimates that approximately 25 exploration wells will be drilled on Beaufort Sea OCS leases. Based on these statistics, the number of exploratory wells expected to be drilled in the Beaufort Sea is only one tenth of the total needed to predict one blowout. However, it would be misleading to forecast the probability of a blowout on the Beaufort Sea OCS based on the extrapolation of observations made in other OCS areas. This is particularly true in view of the hostile operating environment of the Beaufort Sea. As of this writing, 14 wells have been drilled on submerged State lands in the Beaufort Sea. No blowouts occurred during the drilling of these wells.

The adverse effects that would result from a blowout that caused a major oil spill in the Beaufort Sea are largely unknown. Studies of past spills in other areas have shown that the degree of adverse environmental effects ranges from insignificant to severe. The magnitude of effects in the spill area is governed by several factors including the type and quantity of oil spilled, oceanographic conditions, meteorological conditions, season, the biota of the area, previous exposure of the area to oil, and previous exposure of the area to other pollutants. In view of the fact that the dynamic interrelationship among these factors is extremely complex and that our knowledge of the Beaufort Sea ecosystem is incomplete, predicting possible adverse effects at this time would be speculative. Adverse effects that may be observed in an area affected by an oil spill are:

(a) Destruction of phytoplanktonic (microscopic plants that inhabit the water column) primary producers located in the water immediately under the slick, and/or destruction of epontic algae on the underside of sea ice that comes into contact with an underice spill;

(b) Buildup of oil in subtidal bottom sediments;

(c) Damage to benthic and intertidal communities resulting from the toxic and coating properties of crude oil;

(d) Accumulation of hydrocarbons in tissues of detritus, filter, and ciliary-mucous feeders that injest and assimilate hydrocarbons contained in oil-contaminated food;

(e) Destruction of the planktonic (in the water column) and epibenthic (on the sea floor) invertebrates immediately around the slick;

(f) Destruction of birds that are oiled by coming into direct contact with the slick, and destruction of bird habitat;

(g) Irritation of the skin and eyes of pinnipeds by direct contact with oil, contamination of rookeries, and ingestion of oil; and

(h) Interference with skin respiration in some whales, and fouling of baleen plates (food gathering filters) and blow holes by direct contact with spilled oil.

3. *Transportation Activities.* Personnel and supplies will probably be moved to and from the drilling site either by boat, helicopter, or surface vehicle. The BLM estimates that from two to six support and supply vessels and two to six helicopters will be employed for this purpose during exploration activities. Boat traffic will be restricted to a two to three month period during the summer after the sea ice breaks up. It is anticipated that passengers and freight will be flown in fixed wing aircraft from Fairbanks or Prudhoe Bay to base camps nearby the drill site and from base camps to the drill site by helicopter. During the winter season (November through March) ice growth may also allow over-ice, ground vehicle support of operations.

The adverse effects of these activities on the Beaufort environment are associated primarily with noise and visual disturbance created by boat and helicopter traffic. Adverse effects that may result include:

(a) Disturbance of certain bird species resulting in changes in nesting and feeding habits;

(b) Disturbance of certain seal species resulting in abandonment of traditional hauling out areas, breeding rookeries, and foraging areas; and

(c) Disruption of migration patterns of the endangered bowhead whale.

Lessees were advised in the Beaufort Sea Notice of Sale document that, during certain times of the year, fixed wing aircraft and helicopters involved in the development of Federal OSC leases must not fly over certain sensitive areas at altitudes of less than 1500 feet.

The proposed Arctic OCS Orders were designed primarily to provide governing guidance with respect to the technical aspects of drilling activities. Prior to producing and transporting oil and gas that may be discovered during exploration, additional Arctic OCS Orders will be developed to address well completions and workover operations, oil and gas pipeline design and construction activities, and production measurement and commingling. All anticipated liquid and solid discharges (e.g., drill muds and cuttings) are regulated by the Environmental Protection Agency (EPA) through its National Pollution Discharge Elimination System (NPDES) permitting process. Prior to discharging any substances into the marine environment, the lessee must obtain an NPDES permit from the EPA. In some cases, the method of disposal will have to be approved by the USGS District Supervisor. Construction of the drilling platform (e.g., gravel island) requires a "fixed structure" permit from the U.S. Army Corps of Engineers as mentioned in Part I.C.

Most other exploration activities that could result in adverse environmental effects are controlled by Federal lease stipulations. The ramifications of this special stipulation mechanism are also discussed in part I.C.

II. Environmental Effects of the Proposed Arctic OCS Orders

The analysis of the potential environmental effects of the proposed Arctic OCS Orders is presented below in an Order-by-Order fashion. The analysis of each proposed Order includes a detailed summary of the proposed Order provisions, identifies those provisions that are Arctic-specific, and discusses the potential environmental impacts. A complete text of each proposed Order is contained in the Appendix

A. Proposed Arctic OCS Order No. 1

Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects.

Proposed Arctic OCS Order No. 1 would require lessees to mark platforms, drilling rigs, drilling ships, artificial islands, and wells with signs of standard specifications that identify the operator (representative of the lessee), the specific OCS lease block, and well number. On artificial islands, only one sign must be installed in a prominent location on the island.

The proposed Order also provides that all oil and gas operations-related subsea objects left on a lease which could present a hazard to other users of the OCS be identified by navigational markings as directed by the U.S. Coast Guard District Commander. Implementing this provision will minimize the potential for accidents and oil spills associated with subsea production systems, "stubs," fishing gear, and ship anchors.

Propoosed OCS Order No. 1 would further require that, whenever practicable, all materials, equipment, tools, containers, and other oil and gas related items used on the OCS be properly color coded, stamped, or labeled with the owner's identification prior to use. This means that the owner of objects freed and lost overboard from rigs, platforms, or supply vessels, that may interfere with commercial fishing gear, can be identified. Such markings would have no significant environmental impact. However, implementation of the provisions of proposed Arctic OCS Order No. 1 would mitigate possible adverse impacts of oil and gas related drilling and production operations on fishing, anchoring, shipping, and navigational activities.

B. Proposed Arctic OCS Order No. 2. Drilling Operations

Proposed Arctic OCS Order No. 2 addresses specific procedures for drilling wells. It requires lessees to submit, as part of their Exploration Plans, Development and Production Plans, and Applications for Permit to Drill, detailed information about the drilling platform, drilling rig, well casing program, drilling mud program, blowout-prevention equipment, and other well-control equipment. The proposed Order also requires lessees to submit plans to deal with certain types of emergency situations, including the drilling of a relief well in the event of a blowout that could cause significant adverse effects to human health and safety and the Arctic environment. Finally, proposed Arctic OCS Order No. 2 provides that Exploration Plans and Development and Production Plans include a list of circumstances in which critical drilling operations will be curtailed and requires that personnel involved in drilling and production activities receive training in operational safety and well control. Most of the Arctic-specific provisions of proposed Arctic OCS Order No. 2 were developed to address potential hazards caused by the extremely low temperatures of the Arctic operating environment, ice conditions, permafrost (permanently frozen soil with ice in the pore space), and hydrates (frozen gas and water).

1. Plans and Applications. Proposed Arctic OCS Order No. 2 identifies four emergency situations that the lessee must address in an Exploration Plan or Development and Production Plan. Requirements contained in sections 1.1.a, 1.1.b., 1.1.c., and 1.1.d of the proposed Order are included for operations on the Arctic OCS because of the remoteness of the area and the hostile Arctic environment. They are also included to assure that lessees are prepared to drill one or more relief wells should a blowout occur that requires the drilling of relief wells to restore well control. The specific details of a lessee's plan for drilling relief wells will be based on the season during which drilling operations are to be conducted, the distance of the drill site from shore and offshore islands, the water depth at the drill site, the proposed total drilling depth, the depth of prospective hydrocarbon bearing zones, the type of activities proposed (i.e., exploration or development), the type of drilling facilities that may be available in the area (e.g., gravel islands, ice islands, drillships, barges), and current technologies and techniques for drilling relief wells. A lessee who is not able to show conclusively that he can drill a relief well(s) without undue delay can expect the USGS to find his Exploration Plan or Development and Production Plan to be incomplete. The drilling of one or more relief wells is usually necessary only when all other well-control efforts fail to regain well control.

Lessees must also identify in their Exploration Plans and Development and Production Plans measures that would be taken in the event that a drilling unit or a drilling rig is lost or disabled.

Support craft (sea-going vessels, vehicles, aircraft, air cushion vehicles or other craft which provide personnel and material transport or assistance to a drilling program) are a vital link between the drill site and onshore support facilities. Therefore, lessees will be required to describe the steps to be taken to assure timely replacement of lost or damaged support craft.

Ice is a predominant feature of the Arctic environment. Its formation during freeze-up, presence as solid ice cover over much of the year, and its deterioration during break-up, and associated ice forces, represent features of the environment that must be considered in the design and execution of normal and emergency activities. Exploration Plans submitted by lessees for the Beaufort Sea OCS leases must anticipates ice conditions that are expected to exist at the drill site during planned drilling activities and during the execution of contingency plan activities, such as drilling a relief well to regain control of a blowout well.

The types of information that may be included in the discussion of these emergency situations are:

(a) The availability of relief drilling rigs, platforms, and support craft;

(b) The logistics and equipment for transporting relief equipment to the drilling site;

(c) Alternative methods for handling conditions resulting from the loss of equipment while waiting for replacement of equipment;

(d) A discussion of safety programs, equipment design considerations, and monitoring programs for anticipated hazards;

(e) A listing of safety equipment which will be available and installed at the drill site;

(f) A discussion of oceanographic and meteorological conditions expected to be encountered, and programs for monitoring oceanographic, meteorological, and ice conditions; and

(g) A discussion of geologic hazards including shallow gas, gas hydrates, bottom instability, and ice scour zones.

In evaluating the lessee's plans for responding to emergency situations, the USGS will consider the equipment available at Prudhoe Bay, pre-planned equipment storage at strategic points on the North Slope, and strategies for moving equipment from southern Alaska to the drilling site. The lessee's

consideration of the effects of unfavorable weather conditions on equipment and material transporation schemes will also be evaluated by the USGS.

2. Drilling From Fixed Platforms and Mobile Drilling Units. Proposed Arctic OCS Order No. 2 requires that all fixed platforms and mobile drilling units proposed for use on the Arctic OCS be designed, constructed, and equipped to operate safely under Arctic conditions. Drilling platforms constructed on Beaufort Sea OCS leases must be specifically designed to withstand the hostile Arctic environment, including tremendous forces that ice can exert on these structures. Prior to commencing oil and gas operations, the proposed Order provides that all fixed drilling platforms and mobile drilling units be made available for a complete inspection by the USGS District Supervisor.

The proposed Order requires lessees to conduct shallow geologic hazards surveys or other surveys as required by the USGS District Supervisor and submit a shallow geologic hazards report for each proposed drilling location. The USGS will use this information to verify that lessees do not propose to place drilling structures on sites where hazards such as surface faults, shallow gas deposits, obstructions, or unstable bottoms are present. These requirements ensure that the drilling unit will be located at a site that is free from detectable hazards that threaten human safety or the environment.

Proposed Arctic OCS Order No. 2 requires lessees to include in Exploration Plans and Development and Production Plans for Arctic OCS leases a specific system to monitor, record, and report environmental data relating to ice, oceanographic, meteorological, and performance data. The recording and reporting of site specific data on environmental conditions are necessary to ensure the continued safe day-to-day conduct of the Arctic drilling operations. The information developed is also necessary to assure the use of Best Available and Safest Technologies (BAST) in the design, fabrication, and placement of exploration and subsequent development and production facilities. When an adequate information base has been established for the lease sale area, some of these environmental data reporting requirements may be modified or discontinued if they become unnecessary.

The proposed Order also requires the lessee to provide evidence in the Exploration Plan and Development and Production Plan that the drilling unit proposed for use can safely perform the planned drilling activities and that the drilling equipment, drilling safety systems, and other associated safety, fire-fighting, and pollution-prevention equipment and materials are suitable for use under subfreezing operating conditions. This evidence must include plans, design drawings, and diagrams showing how drilling equipment and drilling safety systems will be protected from subfreezing conditions or include manufacturer's certifications that equipment and safety systems will operate under subfreezing conditions. In addition to furnishing evidence of the operational capability of the drilling units and associated equipment, each drilling unit will undergo a detailed preoperational inspection by the USGS to verify the drilling unit's capability to operate under Arctic conditions.

Proposed Arctic OCS Order No. 2 requires lessees to submit a discussion of the anticipated normal and extreme environmental and operational conditions that may be encountered during the execution of the activities proposed in the Exploration Plan and Development and Production Plan. Plans must indicate how these conditions impact the selection of equipment and materials which the lessee proposes to use.

The proposed Order also specifies that, in the Arctic OCS, a lessee's Application for Permit to Drill from a mobile offshore drilling unit must include a current American Bureau of Shipping Classification, U.S. Coast Guard Certificate of Inspection, or other appropriate classification, and a description of the mobile drilling unit's operational limitations.

Proposed Arctic OCS Order No. 2 provides that applications for installation of fixed drilling platforms or structures, including artificial islands, be submitted to the USGS in accordance with proposed Arctic OCS Order No. 8. Jackup type mobile drilling units which have their jacking equipment removed or have been otherwise immobilized will be considered fixed drilling platforms, and applications to install such platforms must also be submitted in accordance with proposed Arctic OCS Order No, 8.

3. Well Casing and Cementing. Proposed Arctic OCS Order No. 2 requires that wells be cased and cemented to support unconsolidated sediments and to prevent communication of fluids between the formations penetrated. The proposed Order further provides that, if there are indications of inadequate cementing, the lessee must take remedial actions to correct the apparent inadequacies. Proper well casing design and casing setting depths are determined by considering various engineering and geologic factors, including the presence or absence of hydrocarbons, other potential hazards, and water depths. Each casing string must be placed and cemented prior to drilling below each specified casing setting depth. The USGS District Supervisor may approve alternate casing setting depths for those wells which may encounter abnormal formation pressure conditions.

For wells drilled in the Arctic OCS, proposed Order No. 2 requires that all annuli within permafrost zones not protected by cement be filled with a liquid having a freezing point below the minimum permafrost temperature to prevent internal freezeback. Freezeback is a process in which thawed permafrost or water-based solid inside or outside the casing refreezes and generates excessive pressures on the casing that may either burst (internal freezeback) or collapse (external freezeback) the casing. Cement used to bond casing through permafrost zones must be formulated so that it sets before freezing and has a low heat of hydration. In addition to permafrost, the casing design criteria for all wells must include consideration of formation fracture gradients, formation pressure, anticipated surface pressure, and casing setting depths.

Specifically, proposed Arctic OCS Order No. 2 requires that, in areas containing permafrost, the conductor or surface casing be set and cemented after drilling a maximum of 150 meters (492 ft.) below the base of the permafrost. In addition, lessees will be required to cement the conductor casing with a quantity of cement sufficient to fill the calculated annular space between the casing and the wellbore to the top of the casing.

Implementation of the casing and cementing programs prescribed in proposed Arctic OCS Order No. 2 will mitigate the possibility of freshwater zone contamination, lost production, or lost well control which may result in the release of oil and/or gas into the environment and threaten human health and safety.

4. Directional Surveys. Proposed Arctic OCS Order No. 2 requires lessees to obtain directional surveys on all wells. These surveys must be filed with the USGS District Supervisor. They indicate whether the well is drilled in accordance with the planned course of the wellbore. These surveys also provide the information required to locate the "target" of a relief well in the event one or more such wells is needed to control a blowout.

In the Arctic OCS, lessees will be required to obtain directional surveys on vertical wells at intervals that do not exceed 150 meters (492 ft.) during the normal course of drilling operations. This survey interval also applies to directional wells except that directional surveys must be obtained at intervals not exceeding 30 meters (100 ft.) in all planned angle-change portions of the wellbore.

In order to conduct drilling operations that encounter the fewest drilling problems and that are the most economical, lessees normally try to keep the wellbore of exploratory wells close to vertical. The likelihood that the wellbore will deviate from vertical is governed by several factors, such as type and angle of dip of the formations penetrated, pressure on the drilling bit, and rate of drilling.

The proposed requirement to obtain directional surveys is especially important from the environmental point of view. Directional surveys are necessary to keep track of the location of the wellbore. It is also necessary to know the course of a wellbore to ensure that the bottom of the hole stays within the confines of the lease being drilled. Finally, in areas where several wells will be drilled in close proximity, it is important to know the location of the wellbore for each well drilled to avoid accidental intersection of a well being drilled with a previously drilled well.

5. Blowout-Preventer Equipment Requirements. When primary control of the well has been lost due to insufficient drilling mud hydrostatic pressure, it becomes necessary to seal the well by some means in order to prevent an uncontrolled flow or blowout of formation gases or fluids. The equipment which stops the flow and seals the well is called the blowout preventer. It consists of various ram and annular preventer mechanisms attached to the surface casing.

Proposed Arctic OCS Order No. 2 provides that blowout preventers and related pressure control equipment be installed, used, and tested in a manner that ensures positive well control. A specific number of these preventers must be used in drilling every well, and they must be equipped with dual control systems. Further, the proposed Order requires that blowout preventers and related control equipment be adequately protected to ensure reliable operations under Arctic conditions. Special requirements are included for operations conducted from floating drilling platforms which necessitates the placement of the blowout-preventer stack on the sea floor.

Some areas of the Beaufort Sea may be subject to the phenomenon of ice scouring. This phenomenon occurs when moving ice masses come into contact with bottom sediments creating linear depressions in the sea floor. This may necessitate the excavation of depressions in the sea floor (i.e., "glory holes") deep enough to accommodate the placement of blowout-preventer equipment to protect the equipment from possible damage caused by moving ice.

6. Mud Program. The proposed Arctic OCS Order No. 2 outlines specific requirements relating to the use and testing of drilling muds. Drilling muds have a number of critical functions. One of the most important of these functions is to act as the first line of defense against a blowout. During drilling, the mud density is adjusted by adding weighting materials so that the pressure of the column of drilling fluid in the wellbore exceeds the pressure of fluids in penetrated formations. This prevents fluids contained in high pressure formations encountered by the wellbore from escaping into the wellbore. The proposed Order requires that drilling mud programs be approved by the USGS District Supervisor prior to commencement of drilling activities.

Proposed Arctic OCS Order No. 2 further provides that mud temperatures be controlled when drilling through permafrost or associated gas hydrates. Control of mud temperatures has proven to be an effective tool to minimize the thawing of permafrost and decomposition of gas hydrates. The effects of the thawing and refreezing of permafrost were discussed in part II.B.3. A rapid decomposition of gas hydrates casued by a drilling fluid that is too warm would cause a blowout by effectively reducing the drilling mud weight as a result of the influx of gas from the decomposing gas hydrates into the wellbore.

The proposed Order requires the lessee to include, with his Application for Permit to Drill, a tabulation of well depth versus minimum quantities of mud material, including weighting material, that is to be maintained at the drill site to assure well control. When the mud quantity required exceeds the storage capacity of the drilling facility, the lessee must maintain the maximum inventories of mud materials at the site and must obtain USGS approval of the lessee's plans to resupply mud inventories in the event of an emergency. The plan must include an estimate of the time required for delivery of the mud supplies. Daily inventories of mud materials, including weighting materials, must be recorded and maintained at the well site. Drilling operations must be suspended in the absence of minimum quantities of mud material specified in the depth vs. mud quantity table or as modified in the plan approved by the USGS District Supervisor.

Proposed Arctic OCS Order No. 2 directs all enclosed mud-handling areas where dangerous concentrations of combustible gases may accumulate be equipped with gas monitors and an adequate forced ventilation system. Enclosed areas must be:

(a) Ventilated with high-capacity, mechanical ventilation systems capable of changing the air once every 2 minutes. These systems must be automatically activated on signal from a gas detector indicating the presence of gas.

(b) Maintained at a negative pressure relative to the surrounding areas where discharge from an adjacent enclosed area may be hazardous. The negative pressure areas must be protected with a pressure sensitive alarm.

(c) Equipped with gas detectors and alarms that are operative at all times.

(d) Equipped with electrical equipment of the "explosive proof" type. Alternatively, the equipment may be pressurized to prevent the ingress of explosive gases, and where air is used for pressurizing, the air intake must be located outside of, and as far as practicable from, hazardous areas.

The requirements of this section of proposed Arctic OCS Order No. 2 were specifically included for Arctic operations because mud handling areas are enclosed for protection against the cold Arctic environment. Such areas are subject to the accumulation of dangerous concentrations of combustible gases that may be carried from the wellbore to the surface in the drilling fluid. These special Arctic requirements ensure: (1) Proper ventilation, monitoring and detection of combustible gases such as natural gas or hydrogen sulfide, (2) the prevention of the escape of hazardous gases into the other areas of the drilling facility, and (3) the use of explosion proof electrical equipment.

7. Supervision, Surveillance, and Training. Proposed Arctic OCS Order No. 2 requires representatives of the lessee (operators) to provide onsite supervision of drilling operations on a 24-hour basis. A member of the drilling crew or the toolpusher (supervisor of drilling operations) must maintain surveillance of the rig floor continuously from the time drilling operations commence until the well is secured with blowout preventers, bridge plugs, storm packers, or cement plugs. The proposed Order further directs that lessee's

personnel and the drilling contractor's personnel be trained and qualified in state-of-the-art methods of well control and that records of the training be kept at the well site. Specific well-control training requirements are outlined in U.S. Geological Survey OCS Standard, "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T 1). The training requirements are intended to minimized the potential for well blowouts caused by human error. Formal training is supplemented with weekly blowout-prevention drills for all rig personnel as provided in the proposed Order. Drills are to be frequently witnessed by USGS representatives and must be recorded in the driller's log.

8. Hydrogen Sulfide. Proposed Arctic OCS Order No. 2 provides that lessees must follow certain procedures when drilling operations penetrate reservoirs known or expected to contain hydrogen sulfide (H_2S) or in areas where the presence of H_2S is unknown. These procedures are included in U.S. Geological Survey OCS Standard, "Safety Requirements for Drilling Operations in Hydrogen Sulfide Environments," No. 1 (GSS–OCS–T 1). Implementation of this set of standard operating procedures would assure proper safety precautions and crew training should highly toxic H_2S be encountered.

9. Critical Operations and Curtailment Plans. Some operations performed during drilling are considered more critical than others with respect to well control, the prevention of fires, explosions, oil spills, and other unanticipated discharges and emissions. Therefore, lessees must file, as a part of their Exploration Plans and Development and Production Plans, a Critical Operations and Curtailment Plan. The Critical Operations and Curtailment Plan will be reviewed and approved by the USGS as part of the Exploration Plan and Development and Production Plan review and approval process prior to commencing drilling activities.

Proposed Arctic OCS Order No. 2 requires the lessee to list and describe the critical operations that are likely to be conducted on the lease, Before exceeding the operational limits of an approved plan, the lessee's representative must curtail operations and notify the USGS District Supervisor. Under this scheme, the USGS District Supervisor will provide specific approval for proposed actions in advance of the conduct of the critical operation, or he will dispatch personnel to the drilling site to witness and provide approval for actions taken during the critical operation. This part of proposed Order No. 2 provides for additional review of drilling operations that may endanger human safety, the drilling operations, or the environment.

Proposed Order No. 2 requires that the following information be included in the Critical Operations and Curtailment Plan:

(a) A list or description of the critical drilling operations that will be, or are likely to be, conducted on the lease, This list, or description, must specify the operations that are to be commenced, ceased, limited, or that are not to be commenced, ceased, or limited, under given circumstances or conditions, This list must include operations such as:

(1) Drilling in close proximity to another well.

(2) Drill-stem testing (i.e., testing the formation).

(3) Running and cementing casing.

(4) Cutting and recovering casing.

(5) Logging or wireline (i.e., a line used to run survey instruments or other tools into a well) operations.

(6) Well-completion operations.

(7) Moving the drilling vessel off location in an emergency, repositioning the vessel on location, and reestablishing entry into the well.

(b) A list or description of circumstances or conditions under which critical operations must be curtailed. This list or description must be developed from all the factors and conditions relating to the conduct of operations on the lease and must consider, but not necessarily be limited to:

(1) Whether the drilling operations are to be conducted from mobile or fixed platforms.

(2) The availability and capability of containment and cleanup equipment and spill-control system response time.

(3) Abnormal or unusual conditions expected to be encountered during drilling operations.

(4) Known or anticipated meteorological, oceanographic, and ice conditions.

(5) Availability or personnel and equipment for particular operations to be conducted.

(6) Other factors peculiar to the particular lease under consideration.

(c) The name of the person who is in charge of overall drilling operations.

Many critical operations are conducted in the daylight to provide for safer surveillance of monitoring equipment and operations. To compensate for the extended hours of darkness during the Arctic winter, lessees are expected to ensure that adequate lighting is available at the time critical operations are carried out.

Ice loading and ice override are environmental conditions which affect critical operations and may threaten the structural integrity of the drilling platform. The platform design anticipates ice build up and override. Ice forces, or override, become a threat to drilling operations when the exceed the design criteria of the platform. Continuous monitoring of these potential hazards as provided by proposed Article OCS Order No. 2 will alert operators when ice loads or ice override may exceed design criteria and necessitate the curtailment of critical operations.

10. Field Drilling Rules. Finally, proposed Arctic OCS Order No. 2 provides that when sufficient geological and engineering information has been developed as a result of experience gained during a number of drilling operations, the lessee may request, or the USGS Deputy Conservation Manager may require, the establishment of field drilling rules. After field drilling rules have been established by the USGS Deputy Conservation Manager, development wells must be drilled in accordance with these rules and the requirements of proposed Arctic OCS Order No. 2 that are not affected by such rules.

Summary of the environmental effects of proposed Artic OCS Order No. 2.— Issusing proposed Arctic OCS Order No. 2 would have no direct environmental effects except the potential economic impacts experienced by the lessee to comply with the requirements. It is expected, however, that many of the requirements contained in proposed Arctic OCS Order No. 2 would be implemented voluntarily in one fashion or another because of the costly consequences of accidents and loss of well control. It is conceivable that a lessee may willfully ignore requirements established for safety and environmental protection. However, the USGS expects that willfull violations would be rare. Therefore, the actual additional economic burden of the industry is expected to be minimal. Implementation of the provisions of proposed Arctic OCS Order No. 2 by all lessees in the Artic will provide mitigation against the potential for accidents and unnecessary damage to the physical environment.

C. Proposed Arctic OCS Order No. 3. Plugging and Abandonment of Wells

Proposed Arctic OCS Order No. 3 establishes control of the plugging and abandonment of wells which have been drilled for oil and gas. For permanent abandonment of cased portions of wells,

cement plugs must be spaced to isolate fresh water, oil, or gas zones. Plugs are required at the bottom of the deepest casing where an uncased hole exists. Plugs or cement retainers must be placed 30 meters (100 ft.) above and 30 meter (100 ft.) below any perforated interval of the wellbore used for production of oil and gas. A "surface" plug 45 meters (150 ft.) long must be placed with the top of the plug 45 meters (150 ft.) or less below the ocean floor. A pressure or weight test must be made on top of the first plug below the surface plug. The space between plugs must be filled with muds or other fluids of sufficient density to exceed the greatest formation pressure encountered in drilling the interval.

When a well is temporarily abandoned, that is, when the lessee intends to reenter the well at a later time, proposed Arctic OCS Order No. 3 provides that a bridge plug or a cement plug be set at the base of the deepest casing string. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole. Also, the lessee must set a retrievable or permanent bridge plug, or a cement plug at least 30 meters (98 ft.) in length into the casing between 5 and 60 meters (16 and 197 ft.) below the ocean floor. For temporary abandonments, placement of a surface plug is not required.

Proposed Arctic OCS Order No. 3 specifies that the space between the plugs must be filled with a fluid of sufficient density to exceed the greatest formation pressure encountered while drilling the interval. Further, the proposed Order provides that fluid left in the well opposite permafrost zones at abandonment must have a freezing point below the temperature of the permafrost zone and must be treated to minimize corrosion of the casing. The proposed Order also provides that the lessee obtain approval of the USGS District Supervisor prior to leaving oil base fluids in the hole. Implementation of these requirements will minimize the possibility of casing damage from internal freezeback or casing corrosion that may occur subsequent to abandonment.

Proposed Arctic OCS Order No. 3 requires that cement used as plugs through permafrost be formulated to set before freezing and to have a low heat of hydration. The use of cements with these properties has proven successful when cementing through permafrost zones in the Arctic. Permitting the use of conventional cement, which has a high heat of hydration, may cause an unduly large amount of thawing of permafrost. The refreezing of the surrounding formation has been known to cause damage to the casing string (e.g., freezeback). Conventional cement may also freeze before setting, thus rendering plugs ineffective. Either situation could lead to leakage of formation fluids into the marine environment.

Finally, Proposed Arctic OCS Order No. 3 provides that the casing and piling on the sea floor must be removed to a depth below the ocean floor as approved by the USGS District Supervisor. Implementation of the requirements that the sea floor above each final abandonment must be cleared will minimize hazards to navigation and fishery interests.

Proposed Arctic OCS Order No.4 Determination of Well Producibility

The main purpose of proposed Arctic OCS Order No. 4 is to protect the United State' interest in its royalty share of OCS oil and gas. It also serves other administrative purposes. (See Solicitor's Opinion M–36925 for details.)

This proposed Order establishes a procedure for determining whether the lessee has one well on his lease which is "producible," that is, the well is capable of producing oil or gas in paying quantities. The principal form of evidence of producibility will be a "production test" for oil or a "deliverability test" for gas. During these tests, which usually last 2 to 4 hours, a lessee will burn off the produced oil or gas in a hot flame. This practice may produce some air pollution. The USGS has the responsibility for controlling air pollution related to oil and gas exploration and production on the OCS with its regulation 30 CFR 250.57 (1980).

Implementation of the procedures proposed in Arctic OCS Order No. 4 will not significantly affect the environment.

E. Proposed Arctic OCS Order No. 5. Production Safety Systems

Proposed Arctic OCS Order No. 5 sets forth requirements for the design, testing, installation, and operation of production safety systems in accordance with Section 21 of the OCS Lands Act Amendments. This proposed Order requires the use of BAST. Under BAST, the lessee is encouraged to continue the development of improved safety-system technology. As research and product improvement result in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used. If such technologies provide a significant, cost-effective, incremental benefit to safety, health, or the environment, they will be required to be used if determined to be BAST. Conformance to the standards, codes, and practices referenced in the proposed Arctic OCS Order No. 5 will be considered by the USGS to be the application of BAST. Specific equipment, procedures, or systems not covered by standards, codes, or practices will be analyzed by the USGS to determine if the failure of such equipment, procedures, or systems not covered by standards, codes, and practices would have a significant effect on safety, human health, or the environment. If such equipment, procedures, or systems are identified, and until specific performance standards are developed or endorsed by the USGS, the lessee must submit such information necessary to indicate that the proposed activity represents the use of BAST. Lessees must also describe and compare the alternatives considered to the specific equipment or procedures proposed for use and provide rationale why one alternative technology was selected in place of another. This analysis must include a discussion of the cost involved in the use of such technology and the incremental benefits gained.

Proposed Arctic OCS Order No. 5 requires that safety and pollution-prevention equipment conform to the following quality assurance standards or subsequent revisions that the Chief, Conservation Division, USGS, approves for use:

a. American National Standards Institute/American Society of Mechanical Engineers Standard "Quality Assurance and Certification of Safety and Pollution-Prevention Equipment Used in Offshore Oil and Gas Operations," (ANSI/ASME–SPPE–1) with all addenda.

b. American National Standards Institute/American Society of Mechanical Engineers Standard "Accreditation of Testing Laboratories for Safety and Pollution-Prevention Equipment Used in Offshore Oil and Gas Operations," (ANSI/ASME–SPPE–2) with all addenda.

The proposed Order provides that all well tubing installations open to hydrocarbon bearing zones be equipped with a subsurface-safety device such as surface-controlled subsurface-safety valve, injection valve, and a tubing plug or a tubular/annular subsurface-safety device unless, after application and justification, the well is determine to be incapable of flowing. In the Arctic, the lessee must furnish evidence that the surface-controlled subsurface-safety devices and related equipment are capable of normal operation under subfreezing conditions. The surface

controls may be located at a remote location.

Proposed Arctic OCS Order No. 5 also provides that in permafrost areas the setting depth of the subsurface-safety device must be approved by the USGS District Supervisor on a case-by-case basis. Until a subsurface-safety device is installed in a well that is open to flow from a hydrocarbon-bearing zone, the well must be attended in the immediate vicinity of the well so that immediate emergency actions may be taken, if necessary.

In permafrost free areas, the subsurface-safety device must be installed at a depth of 30 meters (100 ft.) or more below the ocean floor. In permafrost areas, the setting depth of the subsurface-safety valve must be approved by the USGS on a case-by-case basis. This requirement recognizes that permafrost may be present as deep as 550 to 610 meters (1,800 to 2,000 ft.). Upon drilling the well, the operator may find discontinuous lenses of permafrost at a depth that can only be determined after the well is completed. In this case, he must obtain approval of a setting depth of the device so that it can be set below permafrost. This will preclude the permafrost from adversely affecting the operational capability of the device.

Proposed Arctic OCS Order No. 5 prescribes that surface and subsurface-safety valves conform to standards and specifications approved for use by the USGS at the time of installation. The proposed Order further provides for the testing or checking of these devices at specified time intervals. If a device does not operate correctly, it must be promptly removed and a properly operating device must be put in place and tested. Additionally, all tubing installations open to hydrocarbon-bearing zones and capable of flowing in which the subsurface-safety device has been removed must be identified with a sign placed on the wellhead stating that the subsurface-safety device has been removed. A subsurface-safety device must be available for each well on the platform. In the event of an emergency that delays timely installation of a subsurface-safety device, such as an impending storm, this device must be properly installed as soon as possible with due consideration to personnel safety.

The subsurface-safety valves described in the proposed Arctic OCS Order No. 5 serve as a mechanism for automatically stopping the flow from a well below the ocean floor in the event of an accident or natural event which destroys or threatens to destroy surface well-control equipment. The reliability of such devices is maximized through regular testing. Implementing these requirements will minimize the probability of a blowout from a producing well.

The proposed Order also requires that all production facilities, including separators, treaters, compressors, headers, and flowlines, be designed, installed, and maintained in a manner which will facilitate an efficient, safe, and pollution-free operation.

Proposed Arctic OCS Order No. 5 further provides that the lessee furnish, in the Development and Production Plan, evidence that the surface-safety systems and related equipment are capable of normal operation under subfreezing conditions and that all equipment and operating procedures take into account floating ice, icing, and other hazardous environmental conditions that may occur in the Arctic.

Proposed Arctic OCS Order No. 5 would establish requirements for the design, installation, operation, and testing of surface-safety systems for new platform production facilities and specifications for wellhead surface safety valves. Prior to the installation of platform equipment, the proposed Order requires that lessees submit to the USGS for design approval information related to equipment, piping, fire-fighting, electrical-system, gas-detection, and safety-shutdown systems. A Safety Analysis Function Evaluation Chart must also be submitted. This chart identifies functions related to sensing devices, shutdown devices, and emergency-support systems. The chart also provides a means of verifying the design logic of the basic safety system.

Proposed Arctic OCS Order No. 5 would establish safety and pollution-control requirements for the operation of pressure vessels, flowlines, pressure sensors, emergency shutdown systems, engine exhaust systems, glycol dehydration units, gas compressors, fire-fighting systems, fire and gas detection systems, electrical equipment, and erosion detection and measurement equipment. Adherence to these requirements would minimize the probability of failures of this equipment and, thus, help to insure safe operations. The proposed Order also prohibits bypassing or blocking out of safety devices unless they are temporarily out of service for startup, maintenance, or testing purposes. Bypassed or blocked out functions must be monitored continuously.

Whenever certain activities which could increase the probability of the occurrence of an undesirable event are conducted simultaneously with production operations, a "General Plan for Conducting Simultaneous Operations" must be filed with the USGS District Supervisor for approval. These activities include drilling, workover, wireline, pumpdown, and major construction operations. The intent of this requirement is to permit USGS review of the conduct, control, and coordination of the proposed operations to determine whether the operations can be conducted simultaneously without significantly increasing the risk of accidents or spills.

Prior to conducting welding or burning activities, proposed Arctic OCS Order No. 5 requires lessees to submit a plan describing personnel requirements and designating safe welding areas. Procedures for establishing safe welding areas and for conducting operations outside such safe areas are specified in the proposed Order. Implementation of these requirements would reduce the potential for explosions that may result in injuries and/or unanticipated pollution.

The proposed Order provides that all safety-system devices be tested by the lessee at specified intervals or more frequently if operating conditions warrant. Proposed Arctic OCS Order No. 5 requires lessees to maintain records for a minimum period of 5 years for each subsurface-safety device installed. These records must be available for review by any authorized representative of the USGS. The records must show the present status and history of each device, including dates and details of installation, inspection, testing, repairing, adjustments, and reinstallation. To mitigate the potential for accidents resulting from human error, all personnel engaged in installing, inspecting, testing, and maintaining safety devices must receive the specific training outlined in proposed Arctic OCS Order No. 5.

In order to enhance the safety of operations on the OCS, the USGS has established the Failure and Inventory Reporting System. This program applies to all offshore structures, including satellites and jackets, which produce or process hydrocarbons and includes the attendant portions of hydrocarbon pipelines when they are physically located on the structure. When the devices specified are used as a part of the production safety and pollution-prevention system, proposed Arctic OCS Order No. 5 requires the lessee to submit an initial inventory of the safety and pollution-prevention devices, update the inventory periodically, and report all device failures that occur.

Finally, proposed Arctic OCS Order No. 5 sets forth requirements for employee orientation and motivation programs concerned with safety and

pollution prevention in offshore oil and gas operations.

Summary of the environmental effects of proposed Arctic OCS Order No. 5. Issuing proposed Arctic OCS Order No. 5 would have no direct adverse environmental effects except for the economic impacts experienced by the lessee who implements the provisions of the proposed Order. As explained in the summary discussion of proposed Arctic OCS Order No. 2, it is expected that the experienced lessee is likely to adopt procedures and practices similar to those proposed in Arctic OCS Order No. 5 because of the costly consequences of accidents. Therefore, the added economic burden lessees would be subjected to in implementing the proposed Order provisions is likely to be small. Implementing all of the provisions of the proposed Arctic OCS Order No. 5 would mitigate against the potential for production-related hazards to human health and safety and unnecessary damage to the physical environment.

F. Proposed Arctic OCS Order No. 7 Pollution Prevention and Control

Proposed Arctic OCS Order No. 7 addresses prevention of pollution of the marine environment and provides rules for disposing of waste materials generated as a result of offshore operations in a manner that will not "adversely affect the public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean."

1. Pollution Prevention. (a) *Drilling Mud Components.* The lessee or his representative must submit a list of drilling mud constituents, additives, and concentrations expected to be used. This provides the USGS a means to evaluate or require alteration of the use and/or disposal of specific drilling mud components which might be harmful to the environment. The disposal of drilling mud and drill cuttings, sand, and other well solids including those containing oil is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. The lessee must obtain approval of the method of disposing drilling mud and cuttings into the ocean from the USGS District Supervisor. Each request will be reviewed on a case-by-case basis.

(b) *Curbs, Gutters, and Drains for Fixed Platforms or Structures and Mobile Drilling Units.* Proposed Arctic OCS Order No. 7 requires that curbs, gutters, drip pans, and drains be installed in deck areas in a manner necessary to collect all contaminants that are to be piped to a properly designed, operated, and maintained sump system. This sump system must automatically maintain a level sufficient to prevent discharge of oil into OCS waters. Compliance with these requirements virtually eliminates the potential for adverse impacts of drainage from fixed platforms, fixed structures, or mobile drilling units on biological communities, water quality, and commercial fisheries. Implementation of these provisions will also mitigate impacts to the coastline adjacent to the oil and gas activities that could be affected by oil, fuel, chemical residues, or other toxic substances that reach the shore.

On artificial islands constructed in the Arctic, all vessels containing hydrocarbons must be placed inside an impervious berm. The volume enclosed by the berm must be in the excess of the volume of vessels containing hydrocarbons. In addition, the rig mat must be made impervious and all drainage ditches must be directed away from the drilling rig into an impervious sump. Proposed Arctic OCS Orders Nos. 2 and 5, which require that materials suitable for subfreezing conditions and conforming to BAST be used, will ensure that proper lining materials are used to make berms impervious. Implementation of these requirements will ensure that hydrocarbons intended to be used or stored on artificial islands will not be inadvertently discharged into the Arctic environment.

(c) *Solid Material Disposed (Equipment).* The disposal of equipment into the sea is prohibited except under emergency conditions. The location and description of any equipment so disposed of must be reported to the USGS District Supervisor. This requirement is intended to mitigate the potential for interference with navigation and commercial fishing operations.

2. Pollution-Control Equipment and Materials, and Oil Spill Contingency Plans. (a) *Equipment and Materials.* Proposed Arctic OCS Order No. 7 provides that the lessee must submit a description of procedures, personnel, and equipment that will be used in reporting, cleanup, and prevention of the spread of any pollution resulting from an oil spill which might occur during the conduct of exploration or development activities. Pollution-control equipment and materials must be maintained by, or must be available to, each lessee at an offshore location and at an approved onshore location. The equipment and materials must be inspected periodically and maintained in a state of readiness for use. Use of chemical agents or additives for treating of oil spills requires the approval of the USGS Deputy Conservation Manager. The use of equipment and materials not suitable for the types of conditions expected to be experienced in the area of proposed activities will not be permitted when the use of such equipment or materials could result in unnecessary hazards to the safety of personnel or risks to marine, coastal, or human environment. Proposed Arctic OCS Order No. 7 also sets forth requirements for rigorous pollution inspection of manned and unmanned facilities on a daily basis or at intervals prescribed by the USGS Deputy Conservation Manager. The proposed Order would also establish requirements for pollution reports for all oil spills and procedures for notification of proper authorities.

(b) *Requirement for Submission of an Oil Spill Contingency Plan.* Proposed Arctic OCS Order No. 7 requires lessees to submit an Oil Spill Contingency Plan containing descriptions of procedures, personnel, and equipment that will be used to conduct oil spill containment and clean-up activities.

The proposed Order provides that the plan must include: 1. Provisions to assure that full resource capability is known and can be committed during an oil spill. This includes the identification and inventory of applicable equipment, materials, and supplies that are available locally and regionally, both committed and uncommitted, and the time required for deployment of the equipment.

2. Provisions for varying degrees of response effort depending on the severity of the oil spill.

3. Provisions for identifying and protecting areas of special biological sensitivity.

4. Procedures for ensuring the early detection and timely notification of an oil spill, including a current list of names, telephone numbers, and addresses of responsible persons and alternates on call to receive notification of an oil spill, and the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil spill is discovered.

5. Provisions for well-defined and specific actions to be taken after discovery and notification of an oil spill, including:

(a) Identification of an oil spill response operating team consisting of trained, prepared, and available personnel.

(b) Predesignation of an individual as an oil spill response coordinator who is charged with the responsibility and is delegated commensurate authority for

directing and coordinating oil spill response operations.

(c) A preplanned location for an oil spill response operations center and a reliable communications system for directing the overall response operations.

(d) Provisions for disposal of recovered spill materials.

Thirteen oil companies have formed a cooperative oil spill contingency organization (the Alaska Beaufort Sea Oilspill Response Body (ABSORB)) to coordinate oil spill contingency operations for the Beaufort Sea. ABSORB has developed a master Oil Spill Contingency Plan for the Beaufort Sea lease sale area. This plan addresses the equipment availability, both at Prudhoe Bay and at ABSORB facilities on the North Slope, and logistics for carrying out contingency support operations from other locations within the State. The master plan detains state-of-the-art oil spill contingency techniques for Arctic regions, as well as potential untested techniques and equipment. The plan predicts the fates of oil spilled in the Arctic environment (e.g., absorbed in snow, suspended in water column, mixed with bottom sediments and bioaccumulations) to improve the understanding of the types of oil spill contingency equipment needed to respond to an oil spill. The specific details contained in an Oil Spill Contingency Plan will depend on the location of the well, the type of drilling structure proposed for use, and the time of year the well will be drilled. The site specific contingency plan submitted by the lessee for a particular Exploration Plan or Development and Production Plan will incorporate the comprehensive master plan developed by ABSORB.

3. Drills and Training. Proposed Arctic OCS Order No. 7 provides that drills and training classes for familiarization of personnel with pollution-control equipment and operational procedures be conducted on a schedule approved by the USGS Deputy Conservation Manager. The drills must be realistic and include the deployment of equipment. When drill performance and results are deemed inadequate by the USGS, the lessees may be required to increase the frequency and/or change the location of the drills until satisfactory results are achieved. The lessees must ensure that training for familiarization of personnel with pollution-control equipment and operational procedures is provided to the members of the oil spill response operating team. The supervisory personnel responsible for directing the oil spill response operations must receive oil spill control instruction suitable for all seasons during which the operations will be carried out.

Immediate corrective action must be taken in all cases when pollution has occurred. Corrective action taken under the lessee's Oil Spill Contingency Plan is subject to modification by the USGS Deputy Conservation Manager. The USGS has the primary authority to require corrective measures to abate pollution at the source. Implementation of these provisions would minimize the potential for pollution from offshore mobile drilling units and structures through personnel instruction.

4. Spill Control and Removal. Although the emphasis of the other proposed Arctic OCS Orders is on the prevention of oil spills, proposed Arctic OCS Order No. 7 recognizes that accidental spills may occur. It also recognizes that it is not technically feasible to completely control and remove oil that may be accidentally discharged. Implementing the provisions of this proposed Order will ensure that the lessees have ready access to the best practical pollution-control equipment for the area and for the prevailing Arctic conditions, and that personnel are trained to use the equipment effectively. The lessee's Oil Spill Contingency Plan must provide sufficient flexibility to permit the use of different spill control strategies for different environmental conditions. This will provide for the use of mechanical and/or chemical pollution-control and cleanup measuress that are best suited to the prevailing environmental condtions and will maximize protection of biological communities, shoreline resources, and commercial fishing interests.

G. Proposed Arctic OCS Order No. 8. Platforms and Structures

The provisions of proposed Arctic OCS order No. 8 apply to all new platforms and structures proposed for use in the Arctic and all major modifications and major repairs to platforms and structures. The proposed Order provides that all new platforms or other structures, or major modification to platforms or other structures, be subject to review under the requirements of the Platform Verification Program. This program was designed to verify the structural integrity of platforms and structures proposed for use on the OCS. The specific requirements for verifying structural integrity are contained in the document entitled "Requirements for Verifying the Structural Integrity of OCS Platforms" published by the USGS.

Proposed Arctic OCS Order No. 8 provides for third party verification of all plans for the design, fabrication, and installation of offshore structures. All structural plans must be certified by a registered professional structural engineer or a civil engineer specializing in structural design. Under this program, the lessee retains a qualified approved and certified third party verification agent (CVA) to examine structural integrity of platforms or artificial islands. Plans for design, fabrication, and installation of an offshore structure and the CVA's reports of his examination of these plans are submitted by the CVA to the USGS Deputy Conservation Manager, who forwards them to the USGS Platform Verification Section for analysis. This section reports their recommendations back to the USGS Deputy Conservation Manager who has the final authority to approve or disapprove use of the platform. In the event of unsatisfactory findings, the lessee is responsible for making necessary corrections and providing subsequent reevaluations until prescribed verifications objectives are obtained.

Only those CVA's who have submitted their qualifications to the USGS for approval and who have been placed on the USGS listing of approved CVA's may verify structural integrity of platforms or structures proposed by lessees for use on the OCS

Proppsed Arctic OCS Order No. 8 requires the lessee to submit a Design Plan and a CVA's Final Design Report that includes design documentation, general platform information, environmental and loading information, foundation and structural information, and the design verification. Also, under the proposed Order provisions, proposals to use new platforms or other structures or to modify platforms or structures which are subject to review under the requirements of the Platform Verification Program, must be accompanied by a Fabrication Verification Plan. Subsequent to the submittal of the CVA's Fabrication Verification Report, the lessee must also submit an Installation Verification Plan and a CVA's Final Installation Report.

Finally, proposed Arctic OCS Order No. 8 requires that, for the functional life of the platform or other structure that is subject to the provisions of the proposed Order, the lessee compile, retain, and make available to the USGS for review the as-built structural drawings, the design assumptions and analysis, and a summary of the Non-Destructive Examinations (NDE) records.

In summary, proposed Arctic OCS Order No. 8 provides technical review of platform and structure design, fabrication, and installation.

Implementation of the provisions of the proposed Order will impose some minor economic impacts on the lessee. However, implementation will also minimize the probability of platform or structure failures including those failures that may result in loss of human life or other serious environmental damage.

H. Proposed Arctic OCS Order No. 12. Public Inspection of Records

Proposed Arctic OCS Order No. 12 sets forth requirements relating to the public availability of data and records concerning offshore petroleum operations. Under the proposed Order, specific types of data and records pertaining to drilling and production operations, well test, sale of lease production, accidents, inspections, and pollution incidents must be available for public inspection. Privileged information, such as certain geological and geophysical data, would be made available for public inspection with the lessee's consent or after a fixed period of time has elasped. By making operations data available, this proposed Order permits increased public awareness of OCS activities and involvement in OCS oil and gas programs. Increased public interest and understanding should result in continuing improvements in the safety and pollution-prevention programs of both the industry and the Government.

Implementation of the provisions of proposed Arctic OCS Order No. 12 would have no significant environmental effects.

III. Alternatives to the Proposal

Three alternatives to the proposed Arctic OCS Orders have been considered. They are:

(A) No Arctic OCS Orders—do not attempt to use the OCS Order scheme to provide guidance for the activities that are addressed by the proposed Arctic OCS Orders beyond the statement of requirements contained in the Department's OCS Oil and Gas Operating Regulations;

(B) Less stringent OCS Orders—use the OCS Order scheme but do not develop special provisions to address activities carried out in the unique Arctic OCS operating environment; and

(C) More stringent OCS Orders—use the OCS Order scheme and include additional, more constraining operating requirements and restrictions than are contained in the proposed Arctic OCS Orders.

Each alternative will be discussed in a comparative manner. This comparison will be accomplished by identifying the differences between an alternative and the proposed Orders and discussing the differences in potential environmental effects.

A. No Arctic OCS Orders

The alternative of not issuing special OCS Orders for operations in the Arctic environment would result in the USGS relying on the Department's existing offshore oil and gas operating regulations to provide control over those activities addressed by the proposed Arctic OCS Orders. The operating regulations are applicable to all OCS areas including the Beaufort Sea. A complete text of these regulations is contained in Part 250 of Title 30, Code of Federal Regulations (30 CFR Part 250).

In general, the operating regulations address the conduct of offshore oil and gas activities in less specific detail than that found in the proposed Arctic OCS Orders. The regulations are designed in this manner so they can be generally applied to all OCS areas. The operating regulations contain provisions which allow the USGS to obtain "other data and information as the Director may require." They also require the lessee to conduct certain prescribed activities "in a manner approved or required by the Director." The type and detail of information that the USGS requires and the specific manner in which certain activities must be conducted are dictated in large part by the particular OCS area in which the activities are to be conducted. Specific requirements imposed by the USGS on a lessee in one area may not be appropriate in another OCS area. For example, the proposed Arctic OCS Orders require that a lessee conduct certain activities in a manner that will prevent excess thawing of permafrost that is encountered during drilling operations. These requirements would be unnecessary in areas like the Gulf of Mexico where permafrost is nonexistent.

Unlike the proposed Arctic OCS Orders, the OCS oil and gas operating regulations do not contain requirements exclusive to Arctic activities. The proposed Arctic OCS Orders provide a mechanism for identifying to the OCS lessees Arctic-specific requirements needed for planning and conducting offshore oil and gas activities. For example, the regulations require that the lessee submit, as part of the Exploration Plan, a description of the safety features and pollution-prevention control features for the equipment to be used, including oil spill containment and cleanup plans (30 CFR 250.34–1). Proposed Arctic OCS Order No. 2 clarifies part of this general requirement. Plans submitted for OCS leases in the Arctic must include provisions for dealing with certain emergency situations involving the drilling of a relief well in the event of a blowout, loss or disablement of a drilling unit or a drilling rig, loss or damage to support craft, and hazards unique to the site of the drilling operations, including conditions such as solid ice cover, freeze-up, or breakup. Unless this information is included in the plan, the USGS would have insufficient information on which to base responsible decisions with respect to the approval of plans describing activities to be conducted in the Arctic.

If lessees are not given early notice of these specific information requirements, either through Arctic OCS Orders or some other mechanism, it is likely that many of them will fail to include one or more bits of needed information in the development of their Exploration Plans. Because the USGS needs this information to evaluate a plan and make a plan approval decision, many plans would be returned to lessee for completion or modification in accordance with the regulations (30 CFR 250.34–1). This action would increase the work load for industry and Government, create an atmosphere of confusion and frustration for the USGS and the lessee, and ultimately result in unnecessary delays in the approval process.

If OCS Orders are not issued for the Arctic, there will be no specific environmental effects to evaluate. However, as discussed in Part II, implementation of the provisions of the proposed Arctic OCS Orders would help to assure that the possibility of the occurrence of certain environmentally unacceptable events is minimized. In the absence of the proposed Arctic OCS Orders, there would be an increase in the occurrence of misunderstandings on the part of the lessee about the precise manner in which certain exploration activities must be conducted to minimize the potential for adverse environmental effects. Such misunderstandings by lessees could result in a lessee inadvertently taking operational risks that the USGS considers unacceptable for safety and environmental reasons.

B. OCS Orders Less Stringent Than the Proposed Arctic OCS Orders

The OCS Orders that are in effect for the Gulf of Mexico will be considered to represent this alternative. OCS Orders have been in effect for some oil and gas related activities on the Gulf of Mexico OCS since 1957, when the first Order was issued (OCS Order No. 1). During the 23 years that have elapsed, the Gulf of Mexico OCS Orders have been periodically revised to reflect the

knowledge gained through more than 30 years of experience in conducting oil and gas activities on the Gulf of Mexico OCS. This experience includes the drilling of over 18,000 wells by industry.

A comparison of the proposed Arctic OCS Orders and the Gulf of Mexico OCS Orders reveals basic similarities between them. However, in the Gulf of Mexico several OCS Orders have been developed to address many of the oil and gas development and production activities currently taking place. Some of the OCS Orders that will address future development and production activities in the Arctic have not yet been developed. Because production activities are not anticipated in the Beaufort Sea for several years, development of Arctic OCS Orders addressing well completion and workover operations, oil and gas pipeline design and construction activities, and production measurement and commingling can be timed so that Arctic OCS Orders, when issued, will reflect current state-of-art technology and knowledge accumulated through experience. These development and production oriented Arctic OCS Orders will, however, be put into place before any such activities are commenced on Arctic OCS leases.

For the purposes of this analysis, only Gulf of Mexico Orders Nos. 1, 2, 3, 4, 5, 7, 8, and 12 will be considered. These Orders represent the Gulf of Mexico counterparts to proposed Arctic OCS Orders Nos. 1, 2, 3, 4, 5, 7, 8, and 12. A complete text of the Gulf of Mexico OCS Orders was published by the USGS in the **Federal Register** on December 21, 1979 (44 *FR* 76212–76262), and revisions to Orders Nos. 1, 2, 5 and 7 were published on August 18, 1980 (45 *FR* 55126–55132).

Because the Gulf of Mexico OCS Orders were developed for the relatively warm operating environment of the Gulf, they contain no provisions for considering extended periods of subfreezing temperatures, permafrost, or ice conditions. Further, the USGS does not need as much detailed information for certain activities proposed in the Gulf of Mexico because the manner in which these activities will be conducted is well established and the results to be obtained are generally predictable. This is not case in the Arctic OCS areas such as the Beaufort Sea. The principal differences between the Gulf of Mexico OCS Orders and the proposed Arctic OCS Orders are summarized below.

1. *Alternative OCS Order No. 1.* Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects.

This Order generally provides that all large platforms and structures which have helicopter landing facilities be marked with appropriate identification on diagonal corners. Because artificial islands are not used as drilling or production platforms in the Gulf, Gulf of Mexico OCS Order No. 1 does not address them specifically. In the Arctic, artificial islands need only be marked with appropriate identification in one prominent location.

The marking of platforms, by one or more signs, would have no environmental effects. Therefore, there would be no difference in environmental impacts if the Gulf of Mexico OCS Order No. 1 were adopted rather than the proposed Arctic OCS Order No. 1.

2. *Alternative OCS Order No. 2. Drilling Operations.* a. Plans and Applications. Unlike proposed Arctic OCS Order No. 2, Gulf of Mexico OCS Order No. 2 does not require lessee to submit, as part of their Exploration Plan and Development and Production Plan, specific plans to deal with emergency situations involving:

(1) A means of drilling a relief well should a blowout occur;

(2) Loss or disablement of a drilling unit or a drilling rig;

(3) Loss or damage to support craft; and

(4) Hazards unique to the site of the drilling operations including conditions such as solid ice cover, freeze-up, and breakup.

As a result, Gulf of Mexico OCS Order No. 2 does not recognize the special problems created by the remoteness of the Arctic OCS or consider the unique environmental constraints under which activities in the Beaufort Sea will be carried out. In the Gulf of Mexico many drilling operations are being carried out simultaneously in close proximity to each other. Further, operations are close to a highly developed oil and gas infrastructure, with support companies immediately available to provide needed services and assistance in all sorts of possible emergency situations. Finally, ice and subfreezing temperatures over a substained portion of the year are not among the environmental hazards found in the Gulf of Mexico. Submission of plans that address these concerns is, therefore, not necessary for that OCS area.

b. Drilling From Fixed Platforms and Mobile Drilling Units. (1) *Fitness of Drilling Unit.* Gulf of Mexico OCS Order No. 2 does not specifically require that drilling units be designed, constructed, and equipped to operate safely under Arctic conditions.

(2) *Oceanographic, Meteorological, and Performance Data.* Gulf of Mexico OCS Order No. 2 does not require that each Exploration Plan include a discussion of the specific system that the lessee will use to monitor, record, and report environmental data relating to sea ice, oceanographic and meteorologic conditions, and performance data.

The requirement to measure, record, and report oceanographic, meteorological, and performance data is generally not applicable to the Gulf of Mexico OCS area because there exists in the Gulf of Mexico a substantial data base which is readily available to the lessee and the USGS. Once an adequate information base of this type is established in the Arctic OCS area, this requirement may be reduced or eliminated.

(3) *Subfreezing Operations.* There are no specific provisions in Gulf of Mexico OCS Order No. 2 that require the lessee to furnish evidence that all tools, equipment, and materials used during exploration, development, and production activities are suitable for use in Arctic operations. The proposed Arctic OCS Order No. 2 would require the lessee to provide evidence that the tools, drilling safety systems, equipment, and materials used can withstand prolonged periods of Arctic temperatures.

The Gulf of Mexico does not experience extended periods of subfreezing temperatures which adversely affect the function of tools, drilling safety systems, and equipment used in oil and gas activities. Therefore, in the Gulf of Mexico, a requirement that such tools and equipment be able to withstand these conditions is unnecessary.

(4) *Mobile Drilling Units.* Gulf of Mexico OCS Order No. 2 does not require that, for all mobile drilling units, the lessee provide a listing of maximum environmental and operational design characteristics and regional maximum environmental conditions. Neither does it require the lessee to provide current American Bureau of Shipping Classification, U.S. Coast Guard Certificate of Inspection, nor other appropriate classifications for mobile drilling rigs proposed for use.

In the Gulf of Mexico, much of the data and information related to maximum environmental conditions is readily available in the GS files. The certification requirement has not been included in OCS Order No. 2 for the Gulf of Mexico because the Coast Guard has determined that the large number of mobile drilling units operating in the Gulf makes it impractical for the Coast

Guard to enforce a certification requirement at this time.

c. *Well Casing and Cementing.* (1) *General requirements.* Arctic OCS Order No. 2 proposes that the lessee be required to include in the Application for Permit to Drill a proposal to fill all annuli within permafrost zones with cement or a liquid with a freezing point below the minimum permafrost temperature to prevent casing damage caused by freezeback. This Order also proposes that all cement used in permafrost areas have a low heat of hydration to prevent thawing of the permafrost. Gulf of Mexico OCS Order No. 2 contains no such provisions. Gulf of Mexico OCS Order No. 2 does not address design criteria for wells proposed to be drilled through permafrost zones. Permafrost does not occur in the Gulf of Mexico area and, hence, these requirements are not included in the OCS Order No. 2 for that area.

(2) *Conductor and Surface Casing Setting and Cementing Requirements.* Gulf of Mexico OCS Order No. 2 contains no requirement for the use of conductor casing in subsequent wells if drilling of one or more exploration wells at a site has shown that shallow hazards are not present. However, there has been insufficient drilling experience gained on the Arctic OCS to justify the inclusion of this practice in the proposed Arctic OCS Orders. Also, specific depths for setting conductor casing and data to substantiate the proposed setting depths are required to be included in plans for permafrost areas. An alternate method of setting wellheads and well-control equipment below the surface of the seafloor may be required in the Arctic due to the phenomenon of ice scouring (the disturbance of the seabed due to drag of large moving ice masses). This is not a concern when wellheads and other equipment are placed on the surface of a gravel island. These requirements are not addressed in the Gulf of Mexico OCS Order No. 2 because permafrost sea ice is not present in that area.

This section of proposed Arctic OCS Order No. 2 makes additional allowances and sets up criteria for setting casing and cementing through permafrost zones. Such requirements are not applicable to Gulf of Mexico operations.

(d) *Directional Surveys.* Gulf of Mexico OCS Order No. 2 requires that the lessee conduct directional surveys every 300 meters (984 ft.) on "vertical wells" to determine the deviation of the wellbore from vertical. The proposed Arctic OCS Order No. 2 would require that directional surveys be conducted at a minimum interval of 150 meters (492 ft.).

In the Gulf of Mexico, experience gained over many years and thousands of wells has shown that a survey interval of 300 meters (984 ft.) is sufficient to determine whether a well is directional or vertical. In less developed frontier areas, such as the Arctic, drilling experience gained in Prudhoe Bay and the National Petroleum Reserve-Alaska (NPR–A), indicates that a smaller survey interval is necessary to accurately determine departure from vertical. Adopting the alternative of allowing 300 meters (984 ft.) between directional surveys rather than the 150 meters (492 ft.) proposed for the Arctic OCS could result in a reduction in the degree of accuracy in determining the precise location of a wellbore. This reduced accuracy could increase the possibility that a relief well being drilled toward a target blowout well might not be drilled as close to the wild wellbore as desired.

e. Mud Program. Gulf of Mexico OCS Order No. 2 does not specifically address requirements for controlling mud temperatures. Proposed Arctic OCS Order No. 2 specifies that the temperature of drilling muds be controlled to minimize heat loss in permafrost areas. Unlike proposed Arctic OCS Order No. 2, Gulf of Mexico OCS Order No. 2 does not specify the safety precautions to be observed in enclosed mudhandling areas.

f. Critical Operations and Curtailment Plans. Gulf of Mexico OCS Order No. 2 provides few specific details regarding the content of Critical Operations and Curtailment Plans. On the other hand, proposed Arctic OCS Order No. 2 lists a number of specific critical operations that must be addressed in the plan. Further, unlike Gulf of Mexico OCS Order No. 2, proposed Arctic OCS Order No. 2 would require that certain specific circumstances be considered when developing the list of circumstances during which critical operations would be curtailed.

In the Gulf of Mexico, experience gained through conducting numerous drilling operations over the years has allowed lessees to formulate comprehensive plans that anticipate commonly occurring situations that necessitate curtailment of operations. Because this experience has not been gained in the Arctic, it will be necessary to plan for the many different types of circumstances that may arise and which would necessitate the curtailment of critical operations.

Summary of the environmental effects of Gulf of Mexico OCS Order No. 2.—Issuing Gulf of Mexico OCS Order No. 2 in the Arctic would have no direct environmental effects except the potential economic impacts experienced by the lessee to comply with the requirements. It is expected, however, that many of the requirements contained in Gulf of Mexico OCS Order No. 2 would be implemented voluntarily in one fashion or another because of the costly consequences of accidents or loss of well control. It is conceivable that a lessee may willfully ignore requirements established for safety and environmental protection. However, the USGS expects that willful violations would be rare. Therefore, the actual additional economic burden on the industry is expected to be small.

Implementation of Gulf of Mexico OCS Order No. 2 by all lessens in the Arctic could provide some mitigation against the potential for unnecessary human safety risks and damage to the physical environment. However, without consideration of the Arctic-specific aspects of drilling that are included in proposed Arctic OCS Order No. 2, the USGS could not be assured that drilling activities would be conducted in a manner that minimizes the potential for unacceptable adverse environmental effects.

3. *Alternative OCS Order No. 3. Plugging and Abandonment of Wells.* a. *Drilling Mud.* Both Gulf of Mexico OCS Order No. 3 and the proposed Arctic OCS Order No. 3 require that intervals between plugs be filled with a fluid of sufficient density to exert a hydrostatic pressure exceeding the greatest formation pressure encountered while drilling the intervals between the plugs. But unlike proposed Arctic OCS Order No. 3, Gulf of Mexico OCS Order No. 3 does not require the lessee to ensure that fluids left in the well adjacent to permafrost zones have a freezing point below the lowest temperature in the permafrost zone or that these fluids be treated to minimize corrosion of the casing. Leaving oil base fluids in the hole will require prior approval of the USGS District Supervisor. Since permafrost conditions are not experienced in the Gulf of Mexico area, these considerations are not addressed in Gulf of Mexico OCS Order No. 3.

b. *Cement.* Gulf of Mexico OCS Order No. 3 allows the use of conventional cement in the placement of plugs. In the Arctic environment, it has been shown that the use of such cements may be ineffective. Consequently, the proposed Arctic OCS Order No. 3 requirement that cement plugs placed through permafrost zones must be formulated to set before freezing and have a low heat of hydration is necessary for Arctic

operations. The effects of permafrost on cement is not addressed in Gulf of Mexico OCS Order No. 3.

4. *Alternative OCS Order No. 4. Determination of Well Producibility.* The provisions of Gulf of Mexico OCS Order No. 4 and proposed Arctic OCS Order No. 4 are identical. Therefore, there would be no difference in environmental effects if either the proposed Arctic OCS Order or the Gulf of Mexico OCS Order was adopted for Arctic operations.

5. *Alternative OCS Order No. 5. Production Safety Systems.* a. *Use of Best Available and Safest Technologies (BAST).* Both Gulf of Mexico OCS Order No. 5 and proposed Arctic OCS Order No. 5 conform to the standards, codes, and practices related to BAST. The submittal of information in conformance to BAST is required of the lessee on a case-by-case basis as directed by the USGS Deputy Conservaion Manager in the Gulf of Mexico area. Under the proposed Arctic OCS Order No. 5 the lessee will be required to submit information to demonstrate that the activities proposed for the Arctic OCS represent BAST. This is necessary for Arctic operations because exploration of the Arctic OCS is a relatively new activity.

b. *Subsurface-Safety Devices.* Requirements for equipping all tubing installations open to hydrocarbon bearing zones with safety devices such as a surface-controlled subsurface-safety valve, a subsurface-controlled subsurface-safety valve, injection valve, a tubing plug or a tubular/annular subsurface-safety device are the same in Gulf of Mexico OCS Order No. 5 and proposed Arctic OCS Order No. 5. The only special provision developed for permafrost areas and included in proposed Arctic OCS Order No. 5 is that the setting depth of a subsurface device must be approved by the USGS District Supervisor on a case-by-case basis. This special provision is included to recognize that the permafrost may be present as deep as 610 meters (2,000 ft.). The recommended practice in Arctic completions is to place the devive below the base of the premafrost to insure that permafrost does not affect its operational capability. These concerns are not appropriate in the Gulf of Mexico.

With respect to surface-controlled subsurface-safety valves, the only requirement contained in proposed Arctic OCS Order No. 5 not included in Gulf of Mexico OCS Order No. 5 is that the lessee be required to ensure that subsurface-controlled subsurface-safety devices and related equipment are capable of normal operation under extended periods of subfreezing conditions.

c. *Design, Installation, and Operation of Surface Production Safety Systems.* Lessees in Arctic OCS areas would be required, under proposed Arctic OCS Order No. 5, to furnish evidence that the surface production safety systems are capable of normal operation under subfreezing conditions. The lessees would also be required to ensure that these valves conform to the requirement to use BAST.

The alternative of using surface production safety systems and related equipment not conditioned for operating under subfreezing conditions cannot be practically considered because such devices, if used, could become inoperative under Arctic conditions. Therefore, they would fail to meet the requirements to use BAST and could cause the uncontrolled release of hydrocarbons into the environment. Because subfreezing operating conditions are not experienced in the Gulf of Mexico, Gulf of Mexico OCS Order No. 5 does not address this concern.

6. *Alternative OCS Order No. 7. Pollution Prevention and Control.* Under the "Curbs, Gutters, and Drains for Fixed Platforms or Structures and Mobile Drilling Rigs," subsection of proposed Arctic OCS Order No. 7, the fixed platforms and structures section was expanded to include artificial islands. This requirement is not included in the Gulf of Mexico OCS Order because artificial islands are not used for exploration, development, or production activities in that OCS area. Arctic OCS Order No. 7 proposes that, on artificial islands, all vessels containing hydrocarbons be placed inside an impervious berm. The volume enclosed by the berm must be in excess of the volume of the vessels containing hydrocarbons. In addition, the rig mat must be made impervious, and all drainage ditches must be directed away from the drilling rig into an impervious sump. The alternative of not requiring impervious berms could lead to discharge of hydrocarbon fluids onto the island which could later end up in the marine environment, should an accidental leak occur from the hydrocarbon storage vessels.

7. *Altervnative OCS Order No. 8. Platforms and Structures.* The provisions of Gulf of Mexico OCS Order No. 8 and proposed Arctic OCS Order No. 8 are essentially the same. The proposed Arctic Order does acknowledge that artificial islands are likely to be used in the Arctic and identifies them specifically as a type of platform that is subject to the provisions of the Order. Because the provisions of the two Orders are substantively identical, there would be no difference in environmental effects.

8. *Alternative OCS Order No. 12. Public Inspection of Records.* The provisions of Gulf of Mexico OCS Order No. 12 and proposed Arctic OCS Order No. 12 are identical. Therefore, there would be no difference in environmental effects if either the proposed Arctic OCS Order or the Gulf of Mexico OCS Order was adopted for the Arctic.

C. OCS Orders More Stringent Than the Proposed Arctic OCS Orders

A third alternative to the proposed Arctic OCS Orders is to adopt OCS Orders that offer even greater protection to the environment. Five elements have been evaluated that could be a part of a stricter set of Arctic OCS Orders. Although each element is discussed separately, the USGS could select any combination of them and have more stringent Arctic OCS Orders as the result. The fourth and fifth parts of this alternative are based on the recommendations of counsel for the North Slope Borough. The first three parts are other matters of concern to the USGS.

1. *First Part of the Alternative.* Require that cement used in permafrost zones have a heat of hydration no greater than 25 British thermal units per pound of cement slurry (25 BTU/lb.)

Conducting oil and gas operations through permafrost may pose special problems for operators (representatives of the lessee), as discussed in Part II. Improper drilling procedures in permafrost can result in washouts, fill on bottom, and stuck pipe.

The common practice among operators that drill wells through permafrost is to use dense drilling fluids with controlled temperature and to drill through permafrost as quickly as possible. This practice minimizes thawing of the permafrost and the possible decomposition of the associated gas hydrates, which otherwise could result in wellbore instability. After permafrost is penetrated, casing is set, and then deeper drilling can proceed under normal drilling conditions. Setting casing below the base of the permafrost zone will minimize the permafrost thawing, which, if unchecked, could result in damage to the well casing from thaw-subsidence or freezeback strain.

In order to provide support for the casing and protection for the permafrost, the casing is cemented. The cement is pumped into the well and around the casing as a liquid slurry. As the cement sets it hydrates, that is, it combines with

the water in the slurry. As a product of this chemical reaction, heat is released. This heat is called the heat of hydration and is measured in British thermal units per pound of cement slurry (BTU/lb.).

In the 1940's and early 50's conventional oil cements were used in wells drilled in the Naval Petroleum Reserve No. 4 in Northern Alaska (now called NPR–A). These cements performed poorly in permafrost zones.[5] [6] Other specialized cements, such as mixture of calcium aluminate and fly ash, have not been completely reliable when used in Arctic wells.[7]

Many Arctic operators have turned to gypsum-based cements. These cements display several favorable characteristics, including the ability to set and gain compressive strength at subfreezing temperatures, and exhibit a low heat of hydration, which in turn may prevent additional melting of the permafrost zone in which they are used. The proposed Arctic OCS Order No. 2 requires the operator to use cement with a low heat of hydration. This proposed Order does not specify how low it must be.

The USGS wil review the cementing program included in the lessee's "Application for Permit to Drill." The USGS will approve those cements or cement blends that have been proven successful in permafrost. The gypsum-based cements, for example, have proven to be successful. Operators wishing to use other types of cements in permafrost will have to submit evidence of their suitability. Such evidence may consist of laboratory or field test results.

As an alternative to proposed requirement, the USGS might require that cement used in permafrost zones have a heat of hydration no greater than 25 BTU/lb. The benefit of this requirement, if implemented, is that it would tend to reduce the thaw of the permafrost and the possible decomposition of the associated gas hydrates next to the wellbore in wells drilled in permafrost areas. This requirement would prohibit the use of cements if they had a heat of hydration higher than 25 BTU/lb. Table 1 illustrates the implications of this alternative.

Table 1. *Heats and hydration of cements that have been used in oil and gas wells*

Type of cement	Heat of hydration (Btu/lb.)	Use in permafrost allowed [1] [2] [3]
API Class G	118	No
API Class H	120	No
50% Class H with 50% Fly Ash + 2% Gel.	91.4	No
Calcium Aluminate Cements and 50% Fly Ash (10% Salt by Weight of Water).	57-92	No
Gypsum-Based Cements	15-18	Yes.

[1] L. F. Maier, M. A. Carter et al., Cementing Materials for Cold Environments *JPT* October 1971.
[2] D. K. Smith, Cementing, *Society of Petroleum, Engineers Monograph*, vol. #4 1976.
[3] Goodman, Malcolm A., "Here is what to consider when cementing permafrost" *World Oil*, December 1977.

The disadvantage of this alternative is that the heat of hydration criterion may be arbitrarily low. We do not have evidence that a 25 Btu/lb. maximum heat of hydration is appropriate. We are not yet able to measure the effects of heat transfer into the permafrost resulting solely from hydration because, during cementing operations, several other heat sources in the wellbore can contribute to thawing of the permafrost.

Furthermore, although a low heat of hydration is a desirable cement characteristic, it is not the only criterion used for determining whether a cement will perform well in permafrost. Other desirable characteristics include the ability to set before freezing, the ability to develop enough compressive strength for well operations, a relatively brief placement or thickening time, and a relatively brief waiting-on-cement time.

Consequently, adoption of this alternative would prohibit operators from using a certain type of cement that is otherwise suitable for permafrost application solely on the basis that it does not meet what may be an unnecessary low maximum value for the heat of hydration.

2. *Second Part of the Alternative.* Require operators to set conductor and surface casing no deeper han 50 meters (164 ft.) below the base of the deepest permafrost zone.

As explained in the first part of this alternative, improper drilling procedures in permafrost zones may result in wellbore instability caused by excessive thawing of the permafrost. They may also lead to decomposition of some associated gas hydrates at lower depths in the permafrost zone, which may result in further stability problems.[8] [9]

A permafrost zone should be drilled quickly and then should be cased. A problem arises in deciding how soon to set the casing after drilling through the pemafrost zone. Proposed Arctic OCS Order No. 2, subsection 3.3.1, generally requires that conductor or surface casing "be set and cemented after drilling a maximum of 150 meters (492 ft.) below the base of the permafrost." This alternative would reduce the maximum to 50 meters (164 ft.).

The advantage of adopting this alternative is that it would minimize the time of interaction between the permafrost and the possible associated gas hydrates and the drilling fluids in the wellbore. This interaction may cause thawing and decomposition problems because of the heat transfer from the circulating muds to the permafrost. Depending on whether the operator runs into trouble while drilling the well, it could take several hours to several days to drill the additional 100 meters (328 ft.) below the permafrost. An early experience in the Canadian Arctic illustrates the problem. One operator, through improper drilling practices, frequently caused excessive thawing of the permafrost which resulted in the enlargement of the wellbore. This, in turn, released large amounts of sand into the drilling fluids. The operator had to stop drilling to recondition the mud. In the meantime the permafrost continued to thaw.[*] [7] Industry has learned from these early experiences, and currently acceptable drilling practices have greatly reduced thawing of the permafrost and the decomposition of any associated gas hydrates. However, certain risks to wellbore integrity remain.

The disadvantage of this alternative is that it might not allow for proper anchoring of the casing. If permafrost thaws, the cement bond between it and the casing weakens. Repeated thawing and refreezing can increase the pressures on the casing and may cause it to burst or collapse. It also may increase the strain on the wellhead, which must support the added weight of poorly bonded casing. To avoid these problems, the lessee plans to anchor the bottom of the conductor or surface casing in consolidated rock below the permafrost. However, the base permafrost may not be well-defined and may, in some cases, extend over a transition zone of several hundred feet. Recognizing this, Alaska's Department of Natural Resources generally requires drillers in Prudhoe Bay to do deeper than 150 meters (492 ft.) below the permafrost. According to the State of Alaska's Conservation Order No. 145, Prudhoe Oil Pool, Rule 3 (June 1, 1977):

(c) For proper anchorage, to prevent uncontrolled flow, and to protect the well from the effects of permafrost thaw,

[5] White, Col., F. L., "Setting cements in below freezing conditions," Petroleum Engineer, August 1952, p. 87.
[6] White, Col., F. L., "Casing can be cemented in permafrost area," *World Oil*, December 1973, p. 119.
[7] W. C. Cunningham, D. K. Smith, "Cementing through permafrost environment" *A.S.M.E. publication*, June 1977, 77–pet–37.

a string of surface casing shall be set *at least 500 feet* below the base of the permafrost section, but not below 2,700 feet * * * (Emphasis added.)

Consequently, if the USGS makes lessees set casing no lower than 50 meters (164 ft.) below the permafrost, it may cause the casing in some wells to be anchored insecurely. This, in turn, may threaten human safety and the marine environment. The USGS, then, is faced with a trade-off. It must balance the need to shield the permafrost and possible associated gas hydrates quickly with the need to anchor the casing securely.

e. *Third Part of the Alternative.* Require lessees to make directional surveys evey 60 meters (197 ft.) in wells during normal drilling operation.

No well is ever drilled perfectly vertical from top to bottom. Intentional or unintentional hole deviation from true vertical is governed by many factors, such as rock type, formation dip, weight placed on the bit, flexibility of the drill string, use of stabilizers, reamers, or special bits and hole deflection tools. Whatever the reason for the deviation, lessees run directional surveys that indicate the amount of deflection from vertical, as well as direction or azimuth of this deflection, in order to calculate the location of the wellbore.

Several types of directional survey instruments exist. One is a single-shot survey instrument which contains a compass on the bottom, a glass marked with concentric rings, a plumb bob dangling above the glass, and a camera. The camera photographs the position of he bob on the glass and the compass, thus showing the angle and direction of the well at that point. The instrument is called "single-shot" because it takes only one photograph. Another type of instrument is the multiple-shot survey. It operates like the single-shot, but can take several photographs at various depths in the well. A third type is a continuous-recording directional survey. This permits the operator to make measurements from the top to the bottom of the well at close intervals. A fourth type differs significantly from the first three. A lessee using the first three instruments must stop drilling to run the survey. But the fourth instrument, a directional orientation tool, allows the operator to run a continuous survey while drilling. The tool consists of a data-gathering probe behind the drillbit, a wireline to the surface, and a readout on the rig displaying the data.[10]

[10] Enenbach, Joseph H., "Directional Drilling Technology Strives for Speed and Accuracy." *Petroleum Engineer International*, Sept. 1980.

Proposed Arctic OCS Order No. 2, Section 4, would impose slightly different requirements on the lessee, depending on whether the well is "vertical" or "directional." A well is vertical if its average angle of deviation is no more than 3 degrees from true vertical. A well with a greater average angle of deviation is directional. In a vertical well, the lessee must measure the angle from the vertical (called the "inclination") at intervals not exceeding 150 meters (492 feet) during normal drilling. He does not have to measure the angle of the hole from magnetic north (called the "azimuth") during normal drilling. In a directional well, the lessee must measure both the inclination and azimuth at intervals not exceeding 150 meters (492 ft.) during normal drilling. Additionally, in parts of a directional well where the lessee has planned to change the angle of the hole, he must measure both angles every 30 meters. Finally, at certain times in both types of wells, the operator must run directional surveys giving both inclination and azimuth. These surveys must be run when the lessee sets either the surface or intermediate casing, when he sets liner pipe, and when he reaches the intended bottom of the well.

The alternative differs from the proposed Order by requiring a survey of inclination and azimuth every 60 meters (197 ft.) during normal drilling in all wells. The advantage of this alternative is that, at certain times during drilling, an operator will know more precisely the course of the well and can determine where its bottom is. This knowledge is important when trying to locate the "target" of a relief well, if one is needed to control the blowout.

Generally, a relief well has greater chance of killing the blowout if it intersects the blown-out well. This way the lessee can pump fluids directly into the wellbore of the blown-out well. But it is also possible to pump the fluids into the wellbore indirectly. This is done by drilling the relief well into the stratum feeding the blowout well, fracturing the rock between the two wells, and pumping fluids from the relief well into the blown-out well through openings in the rock. Thus, the relief well does not always have to intersect the blown-out well precisely,[11] but it generally must come within a maximum predetermined radius, depending on the permeability and fracture strength of the stratum.

More frequent directional surveys, then, would improve the operator's ability to drill a successful relief well. Thus, in those rare situations in which a relief well is needed, this alternative may permit quicker control of a blowout, and may reduce the quantity of oil spilled into the environment.

The disadvantage of this alternative is its cost. Directional surveys cost operators in money and lost drilling time. Additionally, survey measurements taken at a maximum of every 150 meters (492 ft.) permit estimates that usually are within a reasonable range of error. The State of Alaska requires these surveys at least every 500 feet in "unintentionally deviated wells." (20 Alaska Admin. Code 25.050). Like proposed Arctic OCS Order No. 2, the Alaska rule sets a maximum limit; operators are free to run more frequent surveys. Some operators do.

4. *Fourth Part of the Alternative.* Require operators to be able to complete relief wells within 60 days of a blowout, and require each lessee to build one spare island, for the purpose of drilling a relief well, for each island intended to be used for exploratory drilling.

The advantage of this alternative is that it would provide a platform from which a relief well could be drilled on a year-round basis. It would also require an operator to drill a relief well quickly.

This alternative, however, has several disadvantages. Generally, it would increase the disruption of the marine environment from construction of the extra islands, and would increase the volume of gravel taken from sources onshore and offshore. Futhermore, in some cases, the 60-day deadline would force operators to drill relief wells in dangerous haste. We will turn to these points in greater detail.

Although an oil blowout could occur during exploration drilling, the probability of such an event is very low. The USGS Conservation Division estimates the probability, based on historical offshore records in other areas, at 1 in 10,000. Most offshore exploratory drilling blowouts result from drilling into shallow, high pressure gas pockets. An influx of gas from such a pocket may be difficult to control if the unprotected formations penetrated by the well have low fracture gradients. However, hydrocarbons in the form of oil are normally encountered at greater depths, after several strings of casing have been set, and the integrity of the well has been improved. Should an oil blowout occur, there is a good chance that the well would be sealed off naturally (called "bridging"). Even if an oil blowout does occur during exploration and the well does not bridge, there is a good possibility (depending on the drive mechanism of the reservoir and the structural locations

[11] Adams Neal, "How to Drill a Relief Well", *Oil and Gas Journal*, September 1980.

of the well) that the flow of oil would diminish significantly before the relief well was finished.

Of the 81 blowouts recorded in the Gulf of Mexico OCS between 1956 and 1978, only four were oil blowouts. None of the four oil blowouts occurred during exploratory drilling operations. Thirty-eight of the 81 blowouts ceased flowing naturally. Another 38 were "killed" by pumping down mud, capping, or performing other mechanical operations. Only five of the blowouts were killed with relief wells.

Proposed Arctic OCS Order No. 2 requires operators to identify in their plan of exploration a means of drilling a relief well. The plan will be based on the season for which the operation is proposed, the distance from shore and the offshore islands, water depth, the depth of the proposed wells and prospective wells and hydrocarbon zones, the type of operation and type of other drilling operations in the area (gravel island, ice island, drillship, barge, etc.), and the status of new technical developments. Requirements specifying the type of drilling unit that must be used and the maximum permissible time for site preparation are omitted because of the large number of variables affecting relief well decisions. The relief well options proposed by the operator will have to be acceptable to the USGS Deputy Conservation Manager both from a timing and a technical standpoint.

Although preparation time should be minimized to the extent practicable, initial haste in preparing the location for drilling a relief well could result in serious problems and delays later. Preparation time must be considered in the context of the overall time requirements for the entire relief well operation. Drilling the relief well would probably require between 30 and 120 days. An additional 5 to 15 days might be required to pump down mud and kill the well. This drilling killing operation could take much longer if the relief well is not successful (i.e., if the well does not intersect the reservoir at a point with sufficient pressure drawdown). In this case, the well might have to be sidetracked, or additional wells might have to be drilled. In some cases, more than one relief well might be started at the outset of the emergency drilling program.

Table 2 illustrates the effect that a 15-day difference in relief well site preparation time (from 30 days to 15 days) would have on the total time required to control a blowout well by drilling relief wells in three hypothetical blowout scenarios.

Table 2.—*Total time required to kill three hypothetical blowout wells*

Scenario number	1	2	3
Relief well site preparation (days)	30	30	30
Relief well drilling operations (days)	30	105	120
Blowout well kill operations (days)	*15*	*15*	*30*
Total time (days)	75	150	180
Total time with 50% reduction in well site preparation time (days)	60	135	165
Percent difference in total time required to kill blowout well	20	10	8.3

The type of reductions in relief well site preparation time indicated in Table 2 do not result in large reductions in the overall time required for the entire well control operation. The objective should, therefore, be to minimize preparation time without creating unnecessary environmental risk. For drilling proposed in the open water season, the operator will have to demonstrate that there is a barge or drillship in the area which is suitable for drilling a relief well or that there is a fixed structure, island, or onshore site close enough to support a relief well operation. For drilling operations conducted during the remainder of the year, the operator will have to propose a plan for constructing an artificial island or demonstrate the feasibility of another drilling technique. The plan will also have to indicate the drilling rig and associated equipment which would be used and the manner in which it would be transported and installed. In some cases (i.e., certain types of ice islands), a relief well pad can be easily incorporated into the design of an artificial island. In such cases, a relief well pad would be required. However, providing for such a pad on most gravel islands would be very costly both from an economic and an environmental standpoint. Either a large island or a second detached island would be required to assure relief well capability. Either option would greatly increase gravel use and environmental disturbance. Considering the low oil blowout risk and the amount of time which would be saved relative to the total time required for the relief well operation, such costs are significant. In summary, the relief well options are numerous and dependent on a wide variety of technical and environmental factors.

5. *Fifth Part of the Alternative.* Require that personnel responsible for containing and cleaning up an oil spill have experience in working in ice-infested waters, and require that the operator be able to contain and clean-up a spill of 20,000 barrels per day for 120 days.

a. Require that personnel responsible for containing and cleaning up a spill have experience in working in ice-infested waters. This alternative differs from the proposed Arctic Orders in that it specifies part of the training requirements for oil spill response personnel.

The effectiveness of contingency operations is dependent on both the training of personnel and the adequacy of contingency techniques and equipment. The effectiveness of personnel operating in ice-infested water depends not so much on previous experience as on adequate knowledge of the equipment and techniques to be used. Familiarity with equipment and techniques can be gained through formal classroom training excercises, and periodic field exercises. Both of these requirements already exist in the proposed Arctic OSC Orders.

The Alaskan Beaufort Sea Oilspill Response Body (ABSORB) has been contracted by industry to provide oil spill contingency support for the Beaufort Sea. Part of ABSORB's obligation is the training of industry personnel in Arctic contingency techniques. To fulfill this obligation, ABSORB intends to hold four training schools a year for industry personnel. These training schools will include classroom and field experience.[12]

In addition, the proposed Arctic OCS Orders require an actual field drill for the purpose of showing industry's contingency capability and effectiveness. At this time, the adequacy of personnel when operating under Arctic conditions can be determined. If it is determined that personnel are not prepared, additional training and drills may be required. Industry personnel who will be involved in contingency operations are designated based on their primary responsibilities. These persons work on shifts, so that one team is always available. Few can claim to have actual experience in contingency operations in ice-infested waters, because few spills have occurred in the Arctic, none of which occurred on the OCS. However, contract personnel, such as ABSORB, although beyond the direct regulatory control of lease stipulations and the proposed Arctic OCS Orders, have experience in controlling oil spills in the Arctic.

Addition of this alternative in the Arctic Orders will not increase the environment protection potential of the proposed Orders. The intent of the alternative has already been met in the proposed Arctic OSC Orders, and may be controlled by the USGS through the requirements for additional training and drills, when necessary.

[12] ABSORB, *Oil Spill Contingency Plan*, Appendix C, July 1980.

b. Require that the lessee be able to contain and clean up a spill of 20,000 barrels per day for 120 days. This alternative differs from the proposed Arctic Orders in that it expands the scope of an Oil Spill Contingency Plan to address a specific spill situation.

Recognizing their responsibility to control any size spill, industry traditionally contracts oil spill contingency responsibilities to private organizations. These organizations provide manpower and equipment capabilities for handling large spills. For the Beaufort Sea, industry has formed a cooperative organization, the Alaskan Beaufort Sea Oilspill Response Body (ABSORB), to coordinate oil spill response activities. The ABSORB plan addresses a scenario in which a blowout occurs for 4 months (120 days), but that the flowing oil is ignited after 4 days. The rate of flow is considered at 20,000 barrels per day. The concept of igniting free flowing oil is both realistic, and consistent with the contingency technique of igniting free floating oil.[13] Unique to Arctic contingency operations is the availability of natural contingency materials. Snow, a natural absorbant, and ice, a natural solid barrier, are readily available to contain oil. Open slots in the ice, which provide direct access for oil under the ice to the surface, can be at any width, length, and at any location necessary. These are practical contingency techniques which can be adjusted for any size spill.

In recognition of the need to identify criteria by which to judge the adequacy of an Oil Spill Contingency Plan, the USGS and the U.S. Coast Guard have developed a Memorandum of Understanding which calls for an ongoing agency review of Oil Spill Contingency Plans. This joint responsibility involves the establishment of guidelines by which contingency plans will be approved. It is anticipated that scenarios for large spills will be a major part of these guidelines.

Is it not anticipated that this alternative would increase the environmental protection potential of the proposed Arctic OCS Order. Contingency capabilities for large spills have already been addressed by ABSORB for the Beaufort Sea.

Appendix—The Proposed Arctic OCS Orders

These proposed Arctic OCS Orders incorporate appropriate suggestions which were received in response to the following **Federal Register** Notices:

1. Part V, Vol. 44, No. 115, June 13, 1979, requested comments on the proposed version of Arctic OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12.

2. Vol. 44, No. 127, June 29, 1979, requested comments on the final versions of Arctic OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12 for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Areas as published in the **Federal Register**, Part IV, Vol. No. 44, No. 98, May 18, 1979. This Notice postponed the effective date of the Orders to October 1, 1979.

3. Vol. 44, No. 128, July 2, 1979, requested comments on proposed OCS Order No. 8 and proposed "Operating Procedures for the OCS Platform Verification Program" for the Gulf of Mexico, Pacific, Gulf of Alaska, Atlantic, and Arctic OCS Areas.

4. Vol. 44, No. 189, September 27, 1979, postponed the effective date of the Orders to December 1, 1979, and announced that the final Orders would include the final version of Arctic OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12.

5. Part XII, Vol. 44, No. 247, December 21, 1979, published area OCS Orders Nos. 1, 2, 3, 4, 5, 7, and 12, effective January 1, 1980, for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Orders.

6. Vol. 45, No. 71, April 10, 1980, requested comments on proposed revisions of portions of final OCS Orders Nos. 1, 2, 5, and 7 for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Areas. Prospective lessees and operators for the Arctic Areas were also invited to comment, since these proposed revisions are also applicable to the Arctic OCS Orders.

7. Part VIII, Vol. 45, No. 161, August 18, 1980, published final revisions of certain requirements of OCS Orders Nos. 1, 2, 5, and 7, effective September 15, 1980, for the Gulf of Mexico, Pacific, Gulf of Alaska, and Atlantic OCS Orders.

These proposed Arctic OCS Orders reflect the revision of the oil and gas operating regulations contained in 30 CFR 250, which implements the Outer Continental Shelf Lands Act Amendments (OCSLAA) of 1978. These regulation revisions were published in the **Federal Register**, Vol. 44, No. 209, Part VII, on October 26, 1979, with an effective date of December 13, 1979. Accordingly, it should be noted that the Preamble of each proposed Order cites the new and revised regulations.

In accordance with the GS Director's Delegation of Authority, which was published in the **Federal Register**, Volume 45, No. 52, on March 14, 1980, the change of the title of the position of the "Oil and Gas Supervisor" to "Deputy Conservation Manager" has been incorporated as well as the redelegation of the authority of the "Chief, Conservation Division," to the "Deputy Chief, Conservation Division—Offshore Minerals Regulation," for the approval of the Orders. The new titles of these positions and approval authorty are effective throughout all of the OCS Orders.

Alaska Region—Arctic OCS Orders—Contents

Order No. 1 Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects

1. Identification of Fixed Platforms or Structures
1.1 Large Platforms and Structures
1.2 Small Structures
1.3 Artificial Islands
2. Identification of Mobile Drilling Units
3. Identification of Wells
4. Identification of Subsea Objects
5. Marking of Equipment
6. Departures

Order No. 2 Drilling Operations

1. Plans and Applications
1.1 Exploration Plan and Development and Production Plan
1.2 Application for Permit to Drill
2. Drilling From Fixed Platforms and Mobile Drilling Units
2.1 General Requirements
2.1.1 Fitness of drilling unit
2.1.2 Pre-drilling inspection
2.1.3 Well-site surveys
2.1.4 Oceanographic, meteorological, and performance data
2.1.5 Subfreezing operations
2.2 Mobile Drilling Units
2.3 Fixed Drilling Platforms
3. Well Casing and Cementing
3.1 General Requirements
3.2 Drive or Structural Casing
3.3 Conductor and Surface Casing Setting and Cementing Requirements
3.3.1 Conductor and Surface Casing Setting Depths
3.3.2 Conductor Casing Cementing Requirements
3.3.3 Surface Casing Cementing Requirements
3.4 Intermediate Casing Setting and Cementing Requirements
3.5 Production Casing
3.6 Pressure-Testing of Casing
4. Directional Surveys
5. Blowout-Preventer (BOP) Equipment Requirements
5.1 General Requirements
5.1.1 BOP Equipment
5.1.2 Auxiliary Equipment
5.1.3 Subfreezing Operations
5.2 Subsea BOP Requirements
5.3 Surface BOP Requirements
5.4 Drive Pipe or Structural Casing BOP Requirements
5.4.1 Drilling Operations from Bottom-Supported Rigs
5.4.2 Floating Drilling Operations
5.5 Conductor Casing
5.6 Surface and Intermediate Casing
5.7 Testing of BOP Systems

[13] Pallister, Jeff, *Oil Spill Measures for the Arctic Offshore: Research and Practices*, APOA Review, Volume I, No. 4, p. 8, November 1978.

5.7.1 BOP Testing Frequency
5.7.2 Pressure Testing Surface BOP Systems
5.7.3 Pressure Testing Subsea BOP Systems
5.7.4 Actuation of Auxiliary Well-Control Equipment
5.8 Inspection and Maintenance
5.9 Blowout-Preventer Drills
6. Mud Program
6.1 Mud Control
6.2 Mud Testing and Monitoring Equipment
6.3 Mud Quantities
6.4 Safety Precautions in Enclosed Mud-Handling Areas
7. Supervision, Surveillance, and Training
7.1 Supervision
7.2 Surveillance
7.3 Training
8. Hydrogen Sulfide
9. Critical Operations and Curtailment Plans
10. Field Drilling Rules
11. Departures

Order No. 3 Plugging and abandonment of Wells

1. Application for Approval To Abandon a Well
1.1 Notice of Intention to Abandon a Well
1.2 Subsequent Report of Abandonment
2. Permanent Abandonment
2.1 Isolation of Zones in Open Hole
2.2 Isolation of Open Hole
2.3 Plugging or Isolating Perforated Intervals
2.4 Plugging of Casing Stubs
2.4.1 Stub Termination Inside Casing String
2.4.2 Stub Termination Below Casing String
2.5 Plugging of Annular Space
2.6 Surface Plug
2.7 Testing of Plugs
2.8 Mud
2.9 Clearance of Location
2.10 Cement
3. Temporary Abandonment
4. Departures

Order No. 4 Determination of Well Producibility

1. Application for Determination of Well Producibility
2. Criteria for the Determination of Well Producibility
2.1 Production Tests
2.2 Production Capability Determination
3. Departures

Order No. 5 Production Safety Systems

1. Use of Best Available and Safest Technologies (BAST)
2. Quality Assurance and Performance of Safety and Pollution-Prevention Equipment
3. Subsurface-Safety Devices
3.1 Installation
3.1.1 Subsurface-Safety Valves
3.2 Specification for Subsurface-Safety Valves
3.3 Design, Installation, and Operation
3.4 Surface-Controlled Subsurface-Safety Valves
3.4.1 Testing of Surface-Controlled Subsurface-Safety Valves
3.5 Subsurface-Controlled Subsurface-Safety Valves
3.5.1 Inspection and Maintenance of Subsurface-Controlled Subsurface-Safety Valves
3.6 Tubing Plugs in Shut-in Wells
3.7 Injection Wells
3.8 Temporary Removal for Routine Operations
3.9 Additional Safety Equipment
3.10 Emergency Action
3.11 Records
3.12 Reports
4. Design, Installation, and Operation of Surface Production Safety Systems
4.1 New Platforms
4.2 Specification for Wellhead Surface-Safety Valves
4.3 Submittal of Safety-System Design and Installation Features
5. Additional Safety and Pollution-Control Requirements
5.1 Design, Installation, and Operation
5.1.1. Pressure Vessels
5.1.2 Flowlines
5.1.3 Pressure Sensors
5.1.4 Emergency Shutdown System
5.1.5 Engine Exhausts
5.1.6 Glycol-Dehydration Units
5.1.7 Gas Compressors
5.1.8 Firefighting Systems
5.1.9 Fire and Gas Detection System
5.1.10 Electrical Equipment
5.1.11 Erosion
5.2 General Platform Operations
5.3 Simultaneous Platform Operations
5.3.1 General Plan
5.3.2 Supplemental Plan
5.4 Welding and Burning Practices and Procedures
5.4.1 General Welding, Burning, and Hot Tapping Plan
5.4.2 Designated Safe-Welding and Burning Areas
5.4.3 Undesignated Welding and Burning Areas
5.5 Safety Device Testing
5.6 Records
5.6.1 Surface-Safety Value and Associated Actuator Records
5.7 Safety Device Training
6. Failure and Inventory Reporting System (FIRS)
6.1 Data and Reporting Requirements
6.1.1 Format
6.1.2 Device Coverage
6.1.3 Device Inventory Reporting
6.1.3.1 Initial Inventory
6.1.3.2 Inventory Updates
6.1.3.3 Inventory-Reporting Methods
6.1.3.4 Inventory Verification
6.1.3.5 Inventory-Reporting Deviation
6.1.4 Device Failure Reporting
6.1.4.1 Failure-Data Submittal
6.1.4.2 Failure-Data Verification
6.1.4.3 Failure Definition
6.2 Records
7. Crane Operations
8. Employee Orientation and Motivation Programs for Personnel Working Offshore
9. Requirements for Drilling Rigs
9.1 Fixed Structures
9.2 Mobile Drilling Units
10. Departures

Order No. 6 Procedure for Completion of Oil and Gas Wells (Under Development)

Order No. 7 Pollution Prevention and Control

1. Pollution Prevention
1.1 Liquid Disposal
1.1.1 Drilling-Mud Components
1.1.2 Hydrocarbon-Handling Equipment
1.1.3 Curbs, Gutters, and Drains for Fixed Platforms or Structures and Mobile Drilling Units
1.1.4 Discharges from Fixed Platforms or Structures and Mobile Drilling Units
1.2 Solid Material Disposal
1.2.1 Well Solids
1.2.2 Containers
1.2.3 Equipment
2. Personnel, Inspections, and Reports
2.1 Personnel
2.2 Pollution Inspections
2.2.1 Manned Facilities
2.2.2 Unattended Facilities
2.3 Pollution Reports
2.3.1 Spills
2.3.2 Observed Malfunctions
3. Pollution-Control Equipment and Materials and Oil Spill Contingency Plans
3.1 Equipment and Materials
3.2 Oil Spill Contingency Plans
4. Drills and Training
4.1 Drills
4.2. Training
5. Spill Control and Removal
6. Departures

Order No. 8 Platforms and Structures

1. Applicability
1.1 New Platforms
1.2 Major Modifications and Repairs
1.3 Platform Verification
1.4 References
1.4.1 Operating Procedures for the OCS Platform Verification Program
1.4.2 Requirements for Verifying the Structural Integrity of OCS Platforms
1.4.3 Appendices to Requirements for Verifying the Structural Integrity of OCS Platforms
1.4.4 Commentary on Requirements for Verifying the Structural Integrity of OCS Platforms
2. Responsibility
2.1 Submission
2.2 Certification
2.3 Verification
2.4 Approval
2.5 Notification
3. Submissions
3.1 General
3.2 Design
3.2.1 Design Documentation
3.2.1.1 General Platform Information
3.2.1.2 Environmental and Loading Information
3.2.1.3 Foundation Information
3.2.1.4 Structural Information
3.2.2 Design Verification Plan
3.3 Fabrication
3.4 Installation
4. Records
5. Departures

Order No. 9 Oil and Gas Pipelines (Under Development)

Order No. 10 (Title and Content Reserved)

Order No. 11 Oil and Gas Production Rates, Prevention of Waste, and Protection of Correlative Rights (Under Development)

Order No. 12 Public Inspection of Records

1. Filing of Reports
2. Availability of Records

2.1 Form 9–152—Monthly Report of Operations
2.2 Form 9–330—Well-Completion or Recompletion Report and Log
2.2.1 Prior to Commencement
2.2.2 After Commencement of Production
2.2.3 5 Years' Elapsed Time
2.3 Form 9–331—Sundry Notices and Reports on Wells
2.3.1 "Request for Approval to"
2.3.2 "Subsequent Report of"
2.4 Form 9–331 C—Application for Permit to Drill, Deepen, or Plug Back
2.5 Form 9–1869—Quarterly Oil Well Test Report
2.6 Form 9–1870—Semiannual Gas Well Test Report
2.7 Multipoint Back Pressure Test Report
2.8 Sales of Lease Production
2.9 Availability of Inspection Records
2.10 Availability of Data and Information Submitted by Lessees
2.11 Expired Leases
3. Information Exempt From Public Inspection
3.1 Leases Issued Prior to June 11, 1976
3.2 Leases Issued After June 11, 1976
4. Departures

Order No. 13 Production Measurement and Commingling (Under Development)

United States Department of the Interior, Geological Survey, Conservation Division

Alaska Region, Arctic—OCS Order No. 1

Identification of Wells, Platforms, Structures, Mobile Drilling Units, and Subsea Objects

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.37 and 250.54.

1. *Identification of Fixed Platforms or Structures.*

1.1 *Large Platforms and Structures.* Platforms and structures which have helicopter landing facilities shall be identified at two diagonal corners by a sign with letters and figures not less than 30 centimeters (12 inches) in height with the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the platform or structure is located.

d. The platform or structure designation. The information shall be abbreviated as in the following example:

The Blank Oil Company operates "C" platform on Block 999 of the Salisbury Area. The identifying sign on the platform would indicate:

BOC–SAL–999–C.

1.2 *Small Structures.* Small structures, including single well structures which do not have helicopter landing facilities, shall be identified with one sign only, with letters and figures not less than 7.6 centimeters (3 inches) in height.

The information shall be abbreviated as in the following example:

The Blank Oil Company operates well No. 1 which is equipped with a protective structure in Block 68 in the East Cameron Area. The identifying sign on the protective structure would show:

BOC–E.C.–68–No. 1

1.3 *Artificial Islands.* Artificial islands, such as gravel islands and ice islands, shall be identified as required by subparagraph 1.1 of this Order, except that only one sign is required to be installed in a prominent location on the island.

2. *Identification of Mobile Drilling Units.* Floating platforms, bottom-setting mobile rigs, and drilling ships shall be identified by one sign with letters and figures not less than 30 centimeters (12 inches) in height affixed to the derrick or the heliport so as to be visible to approaching traffic and shall contain the following information:

a. The name of the lease operator.

b. The area designation based on OCS Official Protraction Diagrams.

c. The block number in which the drilling unit is located.

d. The OCS lease number.

e. The well number.

3. *Identification of Wells.* The OCS lease and well numbers shall be painted on the wellhead or on a sign affixed to the wellhead of each singly completed well. In multiply completed wells, each completion shall be individually identified at the wellhead. All identifying signs shall be maintained in a legible condition.

4. *Identification of Subsea Objects.* Prior to the installation of subsea equipment required for lease operations, or in the event of the accidental sinking of an object, the owner shall report the submerged equipment or object to the appropriate U.S. Coast Guard District Commander subject to the following limitations. Reports are not required for equipment or objects that:

a. Are submerged in water depths greater than 305 meters (1,000 feet); or

b. Weigh 18 kilograms (40 pounds) or less and are of such shape or configuration that they are unlikely to snag or damage fishing devices; or

c. Are determined to be located on the seafloor within 46 meters (150 feet) of fixed structures on which approved aids to navigation are maintained.

The report shall contain the object's description, weight, dimensions, location, and the depth of water in which it is located. The U.S. Coast Guard will determine if it is a hazard to navigation and will determine whether it requires marking in accordance with 33 CFR Part 64.

5. *Marking of Equipment.* Whenever practicable, all materials, equipment, tools, containers, and items used on the OCS are to be properly color/coded, stamped, or labeled with the owner's identification prior to actual use. For oil and gas operations, this means the owner's identification, as approved or prescribed by the Director, is to be placed upon all materials, cable, equipment, tools, containers, and other objects which could be freed and lost overboard from rigs, platforms, or supply vessels, and are of sufficient size or are of such a nature that they could be expected to interfere with commercial fishing gear if dropped overboard.

6. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Approved:

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey, Conservation Division

Alaska Region Arctic—OCS Order No. 2

Drilling Operations

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10 and 250.11. All exploratory and development wells drilled for oil and gas shall be drilled in accordance with 30 CFR 250.30, 250.34, 250.36, 250.38, 250.40, 240,41, and the Provisions of this Order except for those provisions superseded by ths issuance of field drilling rules.

This Order requires the lessee to submit plans, applications, data, and other information. In all cases where the lessee(s) has (have) identified another party as designated lease operator in accordance with 30 CFR 250.31 and where the term "operator" is defined in accordance with 30 CFR 250.2(g), the required information may be submitted by the designated lease operator.

In addition to the requirements of this Order, the lessee shall comply with the requirements of paragraph 9, *Requirements for Drilling Rigs,* of OCS Order No. 5.

1. *Plans and Applications.*

1.1 *Exploration Plan and Development and Production Plan.*

In accordance with 30 CFR 250.34, the lessee shall submit Exploration Plans

and Development and Production Plans to the Deputy Conservation Manager (DCM), Offshore Field Operations, for approval. All wells drilled under the provisions of this Order shall be included in the appropriate plan. In addition, the Exploration Plans and Development and Production Plans shall include provisions to deal with emergency situations involving:

a. A means of drilling a relief well should a blowout occur.

b. Loss or disablement of drilling unit or a drilling rig.

c. Loss of or damage to support craft.

d. Hazards unique to the site of the drilling operations including conditions such as solid ice cover, freezeup and breakup.

1.2 *Application for Permit to Drill.* Prior to commencing drilling under an approved Exploration Plan or a Development and Production Plan, the lessee shall file, in triplicate, an Application for Permit to Drill (Form 9–331 C) with the District Supervisor for approval. Additionally, DCM, Offshore Field Operations, will prescribe the number of public information copies to be submitted.

2. *Drilling from Fixed Platforms and Mobile Drilling Units.*

2.1 *General Requirements.*

2.1.1 *Fitness of Drilling Unit.* All fixed and mobile drilling units shall be capable of withstanding the oceanographic, meteorological, and ice conditions for the proposed area of operations. The lessee shall submit with the Exploration Plan or Development and Production Plan evidence to the DCM, Offshore Field Operations, of the fitness of the drilling unit to perform the planned drilling operation.

After a drilling unit has been approved for use in an area, the information listed below need not be resubmitted unless required by the DCM, Offshore Field Operations, or there are changes in equipment which affect the rated capability of the unit. This evidence shall include the following specifications or other information as requested by the District Supervisor:

a. The rated capacity of all major drilling equipment.

b. Drilling safety systems.

c. Firefighting equipment.

d. Pollution-prevention equipment associated with the drilling operation.

e. A schematic diagram of the drilling unit.

f. A "Critical Operations and Curtailment Plan" as described in paragaraph 9 of this Order.

2.1.2 *Pre-Drilling Inspection.* Prior to commencing operations in an OCS area, all fixed drilling platforms and mobile drilling units shall be made available for a complete inspection by the District Supervisor.

2.1.3 *Well-Site Surveys.* Lessees shall submit a shallow geologic hazards report, and conduct such shallow geologic hazard surveys or other surveys as required by the DCM, Offshore Field Operations. The results of these surveys and an analysis of the geologic hazards shall be furnished to the District Supervisor. All data obtained from the surveys and all geophysical data relating to shallow hazards shall be furnished upon request to the District Supervisor. When requested, this data shall include sediment and seabed data, e.g., seabed profiles, sediment consistency, allowable bearing and sliding loads, and nearby potential seabed hazards, i.e., sand waves, slumps, mud slides, permafrost, and deposits of frozen gas hydrates.

2.1.4 *Oceanographic, Meteorological, and Performance Data.* Lessees shall collect and report oceanographic, meteorological, performance data, and monitor ice conditions during the period of operations. The type of information collected, method of collection, and report requirements will be as specified by the DCM, Offshore Field Operations.

2.1.5 *Subfreezing Operations.* Lessees shall furnish evidence that the drilling equipment, drilling safety systems, and other associated equipment and materials are suitable for operations in those areas which are subject to subfreezing conditions.

2.2 *Mobile Drilling Units.* Applications for drilling from mobile drilling units shall include the following:

a. A listing of the maximum environmental and operational conditions used for the design.

b. A listing of the regional maximum environmental conditions, including wave, wind, current, ice loading, icing, storm surges, and seismic motion, and of the unusual site-specific environmental conditions anticipated to be encountered at the drill site during the drilling operations.

c. Current American Bureau of Shipping Classification, U.S. Coast Guard Certificate of Inspection, or other appropriate classifications, with operational limitations.

2.3 *Fixed Drilling Platforms.* Applications for installations of fixed drilling platforms or structures, including artificial islands, shall be submitted in accordance with OCS Order No. 8. Mobile Drilling Units which have their jacking equipment removed or have been otherwise immobilized will be considered fixed drilling platforms, and applications shall also be submitted in accordance with OCS Order No. 8.

3. *Well Casing and Cementing.*

3.1 *General Requirements.* All wells shall be cased and cemented in accordance with the requirements of 30 CFR 250.41(a)(1). The Application for Permit to Drill shall include the casing design safety factors for collapse, tension, and burst. In addition, the Application for Permit to Drill must include a proposal to fill all annuli within permafrost zones with cement or a liquid with a freezing point below the minimum permafrost temperature to prevent internal freezeback. The cement used to cement through permafrost zones shall be designed to set before freezing and shall have a low heat of hydration so as not to thaw frozen formations. Wells drilled in areas which are underlain by freshwater aquifers shall have casing programs which are designed to protect the freshwater zones. In cases where cement has filled the annular space back to the ocean floor, upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment. For the purpose of this Order, the several casing strings in order of normal installation are drive or structural, conductor, surface, intermediate, and production casing. If there are indications of inadequate cementing (such as lost returns, cement channeling, or mechanical failure of equipment on the surface, intermediate, and production casing strings), the lessee shall evaluate the adequacy of the cementing operations by pressure testing the casing shoe, running a cement bond log, running a temperature survey, or a combination thereof before continuing operations. If the evaluation indicates inadequate cementing, the lessee shall recement or take other actions as approved by the District Supervisor. The lessee shall verify the adequacy of the remedial cementing operations as required by the District Supervisor.

The design criteria considered for all wells shall be submitted with the Application for Permit to Drill. The criteria to be considered shall include all pertinent factors for well control, such as:

a. Formation fracture gradients.

b. Formation pressure.

c. Anticipated surface pressure.[1]

[1] Anticipated surface pressure is defined as the surface well pressure which can reasonably be expected to be exerted upon a casing string and its related wellhead equipment. In the calculation of anticipated surface pressure, the lessee shall take into account the drilling, completion, and producing conditions. He shall consider mud densities to be

Footnotes continued on next page

d. Casing setting depths.

e. Permafrost zones.

The lessee shall utilize appropriate drilling technology and state-of-the-art methods, such as drilling-rate evaluation, shale-density analysis, or other appropriate methods in order to enhance the evaluation of conditions of abnormal pressure and to minimize the potential for the well to flow or kick.

All casing, except drive pipe or structural casing, shall be new pipe which meets or exceeds American Petroleum Institute (API) standards, or reconditioned used pipe that has been tested to assure that it will meet or exceed API standards for new pipe. If casing to be used is not fabricated to API standards, the yield strengths of the casing shall be included on the Application for Permit to Drill (Form 9–331 C), provided these specifications are not on file with the USGS.

3.2 *Drive or Structural Casing.* This casing shall be set by driving, jetting, or drilling to a minimum depth of 30 meters (98 feet) below the ocean floor or to other depths, as may be required or approved by the District Supervisor, in order to support unconsolidated deposits and to provide hole stability for initial drilling operations. If this portion of the hole is drilled, the drilling fluid shall be of a type that is in compliance with the liquid disposal requirements of OCS Order No. 7, and a quantity of cement sufficient to fill the annular space of the drilled hole shall be used.

3.3 *Conductor and Surface Casing Setting and Cementing Requirements.*

3.3.1 *Conductor and Surface Casing Setting Depths.* Casing design and setting depths shall be based upon all engineering and geologic factors, including the presence or absence of hydrocarbons, other potential hazards, and water depths. These strings of casing shall be set at the depths specified, subject to approved variation to permit the casing to be set in a competent bed, or through formations determined desirable to be isolated from the well by pipe for safer drilling operations; however, the conductor casing shall be set immediately prior to drilling into formations known to contain oil or gas, or, if unknown, upon encountering such formations. These casing strings shall be run and cemented prior to drilling below the specified setting depths. The District Supervisor may prescribe the setting depths for those wells which may encounter abnormal pressure conditions.

In permafrost-free areas, conductor casing setting depths shall be between 91 meters (298 feet) and 305 meters (1,000 feet) True Vertical Depth (TVD) below the ocean floor, and surface casing setting depths shall be between 305 meters (1,000 feet) and 1,400 meters (4,593 feet) TVD below the ocean floor.

In areas containing permafrost, the conductor or surface casing shall be set and cemented after drilling a maximum of 150 meters (492 feet) below the base of the permafrost. Where conditions warrant, the District Supervisor may approve a program where surface casing may be set at a greater depth below the base of permafrost, but not to exceed 1,400 meters (4,593 feet) TVD below the ocean floor.

Engineering, geophysical, and geologic data used to substantiate the proposed setting depths of the conductor and surface casings (such as estimated fracture gradients, pore pressures, shallow hazards, etc.) shall be furnished with the Application for Permit to Drill.

3.3.2 *Conductor Casing Cementing Requirements.* Conductor casing shall be cemented with a quantity of cement sufficient to fill the calculated annular space up to the top of the casing. Cement fill to the top of the casing shall be verified by the observation of cement returns. In the event that observation of cement returns is not feasible or possible, the method of verifying the cement fill shall be approved by the District Supervisor. Upon approval by the District Supervisor, the cement may be washed out or displaced to a depth not exceeding the depth of the structural casing shoe to facilitate casing removal upon well abandonment.

3.3.3 *Surface Casing Cementing Requirements.* Surface casing shall be cemented with a quantity of cement sufficient to protect all freshwater zones, to provide well control until the next string of casing is set, and with sufficient cement to fill the calculated annular space up to the top of the permafrost zone, and with the cement fill at least 60 meters (197 feet) inside the conductor casing, or as approved by the District Supervisor. Any portion of the annulus opposite a permafrost zone which is not protected by cement shall be filled with a liquid with a freezing point below the minimum permafrost temperature to prevent internal freezeback.

For floating drilling operations that use a one-stack blowout-preventer (BOP) system, a lesser volume of cement is permissible to prevent sealing the annular space between the conductor casing and surface casing, when approved by the District Supervisor. Any annular space open to the drilled hole shall be sealed in accordance with the requirements in Order No. 3 upon abandonment.

After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as approved by the District Supervisor. The results of this test and any subsequent tests of the formation shall be recorded on the driller's report and used to determine the depth and maximum mud weight to be used in the intermediate hole.

3.4 *Intermediate Casing Setting and Cementing Requirements.* One or more strings of intermediate casing shall be set when required by anticipated abnormal pressure, mud weight, sediment, and other well conditions. The setting depth for intermediate casing shall be based on the pressure tests of the exposed formation below the surface casing shoe or on subsequent pressure tests. After drilling a maximum of 15 meters (49 feet) of new hole, a pressure test shall be conducted to obtain data to be used in estimating the formation fracture gradient. Pressure data shall be obtained either by testing to formation leak-off or by testing to a predetermined equivalent mud weight as approved by the District Supervisor. The results of this test and any subsequent tests of the formation shall be recorded on the driller's report and used to determine the depth and maximum mud weight to be used in the hole below the intermediate-casing string.

A quantity of cement sufficient to cover and isolate all hydrocarbon zones and to isolate abnormal pressure intervals from normal pressure intervals shall be used. This requirement for isolation may be satisfied by squeeze cementing prior to completion, suspension of operations, or abandonment, whichever occurs first. Sufficient cement shall be used to provide annular fill-up to a minimum of 150 meters (492 feet) above the zones to be isolated or 150 meters (492 feet) above the casing shoe in cases where zonal coverage is not required. Any portion of the annulus opposite a permafrost zone not protected by cement must be filled with a liquid which has a freezing point below the

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Footnotes continued from last page

used below various casing strings, fracture gradients of the exposed formations, casing setting depths, total well depth, formation fluid type, and other pertinent conditions. Considerations for calculating anticipated surface pressure may vary for each segment of the well. The lessee shall include as a part of the statement of anticipated surface pressure the calculations used to determine this pressure during the drilling phase and the completion phase, including the anticipated surface pressure used for production string design.

minimum permafrost temperature to prevent internal freezeback.

If a liner is used as an intermediate string, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for intermediate casing. The liner shall be tested by a fluid entry or pressure test to determine whether a seal between the liner top and the next larger string has been achieved. The test shall be recorded on the driller's report. If the test indicates an improper seal, the top of the liner shall be squeeze cemented. When such liner is used as production casing, it shall be extended to the surface and cemented to avoid surface casing being used as production casing.

3.5 *Production Casing.* Production casing shall be set before completing the well for production. It shall be cemented in a manner necessary to cover or isolate all zones above the shoe which contain hydrocarbons; but in any case, a calculated volume sufficient to fill the annular space at least 150 meters (492 feet) above the uppermost hydrocarbon zone must be used. Open-hole and slotted-liner completions are permitted when approved by the District Supervisor. Any portion of the annulus opposite a permafrost zone not protected by cement must be filled with a liquid which has a freezing point below the permafrost temperature to prevent internal freezeback.

When a liner is used as production casing below intermediate casing, it shall be lapped a minimum of 30 meters (98 feet) into the previous casing string and cemented as required for the production casing. Testing of the seal between the liner top and the next larger string shall be conducted as in the case of intermediate liners and recorded on the driller's report. If the test indicates an improper seal, the top of the liner shall be squeeze cemented.

3.6 *Pressure-Testing of Casing.* Prior to drilling the plug after cementing, all casing strings, except the drive or structural casing, shall be pressure-tested as shown in the table below. The test pressure shall not exceed 70 percent of the internal yield pressure of the casing. If the pressure declines more than 10 percent in 30 minutes or if there is another indication of a leak, the casing shall be recemented, repaired, or an additional casing string run, and the casing tested again. The above procedures shall be repeated until a satisfactory test is obtained.

Casing and Minimum Surface Pressure

Conductor—1,400 kilopascals (kPa)(203 psi)
Surface—*6,900 kPa (1,000 psi)
Intermediate, Liner, and Production—*10,400 kPa (1,508 psi) or 5 kPa/m (0.22 psi/ft.) whichever is greater

In the event of prolonged drill pipe operations which could cause damage to the casing, the casing shall be pressure-tested, calipered, or otherwise evaluated, as approved by the District Supervisor.

After cementing any of the above strings, drilling shall not be resumed until there has been a time lapse of 8 hours under pressure for the conductor casing string or 12 hours under pressure for all other strings. Cement is considered under pressure if one or more float valves are employed and are shown to be holding the cement in place or when other means of holding pressure is used. All casing pressure tests shall be recorded on the driller's report.

In addition to the time lapse stated above, sufficient time must elapse to allow the bottom 153 meters (502 feet) of annular cement fill, or total length of annular cement fill, if less, to attain a compressive strength of at least 3,448 kPa (500 psi), or, as approved by the District Supervisor, before drilling resumes.

The typical performance data for the particular cement mix used in the well shall be used to determine the time lapse required.

4. *Directional Surveys.* Wells are considered vertical if inclination does not exceed an average of 3 degrees from the vertical. Inclinational surveys shall be obtained on all vertical wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling.

Wells are considered directional if inclination exceeds an average of 3 degrees from the vertical. Directional surveys giving both inclination and azimuth shall be obtained on all directional wells at intervals not exceeding 150 meters (492 feet) during the normal course of drilling and at intervals not exceeding 30 meters (98 feet) in all planned angle-change portions of the hole.

On both vertical and directional wells, directional surveys giving both inclination and azimuth shall be obtained at intervals not exceeding 150 meters (492 feet) prior to, or upon, setting surface or intermediate casing, liners, and at total depth. Composite directional surveys shall be filed with the District Supervisor. The interval shown will be from the bottom of conductor casing or, in the absence of conductor casing, from the bottom of drive or structural casing to total depth. In calculating all surveys, a correction from true north to Universal Transverse Mercator Grid north or Lambert Grid north shall be made after making the magnetic-to-true-north correction. A composite dipmeter directional survey including a listing of the directional computed inclinations and azimuths on a well classified as vertical will be acceptable as fulfilling the applicable requirements of this paragraph.

5. *Blowout-Preventer (BOP) Equipment requirements.*

5.1 *General Requirements.* Blowout preventers and related well-control equipment shall be installed, used, maintained, and tested in a manner necessary to assure well control.

5.1.1 *BOP Equipment.* Blowout-preventer equipment shall consist of an annular preventer and the specified number of ram-type preventers. The pipe rams shall be of proper size to fit the drill pipe in use. The working pressure of any blowout preventer shall exceed the anticipated surface pressure to which it may be subjected, except that the working pressure of the annular preventer need not exceed 34,475 kPa (5,000 psi), unless a higher working pressure is required by the District Supervisor. When the anticipated surface pressure exceeds the rated working pressure of the annular preventer, the lessee shall submit with the Application for Permit to Drill a well-control procedure which indicates how the annular preventer will be utilized and the pressure limitations which will be applied during each mode of pressure control.

All blowout-preventer systems shall be equipped with: a. A hydraulic actuating system that provides sufficient accumulator capacity to supply 1.5 times the volume necessary to close all BOP equipment units with a minimum pressure of 1,400 kPa (203 psi) above the precharge pressure. An accumulator backup system, supplied by a secondary power source independent from the primary power source, shall be provided with sufficient capacity to close all blowout preventers and hold them closed. Locking devices shall be provided on the ram-type preventers. The method of BOP actuation control, such as hydraulic, acoustic, or other methods, shall be described and included in the Application for Permit to Drill.

b. At least one operable remote blowout-preventer-control station, in addition to the one on the drilling floor. This control station shall be in a readily accessible location away from the drilling floor.

*Must not exceed 70 percent of the minimum internal yield pressure.

c. A drilling spool with side outlets, if side outlets are not provided in the BOP body, to provide for separate kill and choke lines.

d. A kill line equipped with 2 kill-line valves is required. The master valve shall be located adjacent to the BOP. This valve shall not normally be used for opening or closing on flowing fluid. The second valve shall be located adjacent to the master valve. This valve shall be used as the control valve.

e. A fill-up line above the uppermost preventer.

f. A choke manifold equipped in accordance with "API Recommended Practice for Blowout-Prevention Equipment Systems," API RP 53, first Edition, February 1976, reissued February 1978, Sections 3A and 3B, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

g. Valves, pipes, flexible steel hoses, and other fittings upstream of, and including, the choke manifold shall have a pressure rating at least equal to the anticipated surface pressure.

h. A wellhead assembly with a working pressure at least equal to the anticipated surface pressure.

5.1.2 *Auxiliary Equipment.* The following auxiliary equipment shall be provided and maintained in operable condition at all times:

a. A kelly cock shall be installed below the swivel, and an essentially full-opening valve of such design that it can be run through blowout preventers shall be installed at the bottom of the kelly. A wrench to fit each valve shall be stored in a conspicuous location readily accessible to the drilling crew.

b. An inside blowout preventer and an essentially full-opening drill string safety valve in the open position shall be maintained on the rig flow at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string.

c. A safety valve shall be available on the rig floor assembled with the proper connection to fit the casing string that is being run in the hole at the time.

5.1.3. *Subfreezing Operations.* The blowout preventers and related control equipment shall be suitable for operations in those areas which are subject to subfreezing conditions.

5.2 *Subsea BOP Requirements.* The minimum requirements for drilling below the casing strings for subsea blowout-preventer stacks are tabulated below:

Drive or Structural, See Notes[1] and [2]
Conductor 1—Annular, 1—Diverter System [3] and [4]
Surface 1—Annular, 2—Pipe Rams, 1—Blind Shear Ram
Intermediate—1—Annular, 2—Pipe Rams[5] 1—Blind Shear Ram

Subsea blowout-preventer stacks shall be equipped with blind shear rams. A subsea accumulator or a suitable alternate approved by the District Supervisor is required to provide fast closure of the preventers and to operate all critical functions in case of loss of power fluid connection to the surface. The blowout-preventer system shall include dual pod control systems in accordance with API RP 53, First Edition, February 1976, reissued February 1978, Subsection 5.B.13, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Prior to the removal of the marine riser for installing casing, the riser shall be displaced with seawater. Sufficient hydrostatic head shall be maintained within the well bore to compensate for the reduction in head and to maintain a safe well condition. If repair or replacement of the blowout-preventer stack is necessary after installation, this work shall be accomplished after casing has been cemented prior to drilling out the casing shoe or by setting a cement or bridge plug or storm packer to assure safe well conditions.

5.3 *Surface BOP Requirements.* The minimum requirements for drilling below the casing strings for conventional surface blowout-preventer stacks are tabulated below:

Drive or Structural, 1—Annular, 1—Diverter System [1]
Conductor, 1—Annular, 1—Diverter System [1]
Surface, 1—Annular, 2—Pipe Rams, 1—Blind Ram
Intermediate, 1—Annular, 2—Pipe Rams,[2] 1—Blind Ram

5.4 *Drive Pipe or Structural Casing BOP Requirements.*

5.4.1 *Drilling Operations from Bottom-Supported Rigs.* Before drilling below this string with a bottom setting rig, a diverter system utilizing an annular-type preventer and related equipment shall be installed for circulating the drilling fluid to the drilling structure. The diverter system shall be equipped with remote-control valves in the main and diverter flow lines that can be operated from the control panel prior to shutting in the well. The diverter lines shall vent in different directions to permit downwind diversion. A schematic diagram and operational procedure for the diverter system shall be submitted with the Application for Permit to Drill (Form 9–331 C) to the District Supervisor for approval.

5.4.2 *Floating Drilling Operations.* In drilling operations where a floating or semi-submersible type of drilling vessel is used and formation competency at the structural casing setting depth is not adequate to permit circulation of drilling fluids to the vessel while drilling the conductor hole, a program which provides for safety in these operations shall be described and submitted to the District Supervisor for approval. This program shall include all known

[1] When drilling fluids are circulated to the drilling vessel, a diverter system as described in subparagraph 5.4.1 shall be installed on top of the marine riser.

[2] If returns to the surface cannot be established, refer to subparagraph 5.4.2.

[3] The choke and kill lines or equivalent vent lines, equipped with necessary connections and fittings, can be used for diversion, if approved by the District Supervisor, or an annular preventer or pressure-rotating, packoff-type head, equipped with suitable diversion lines, shall be installed on top of the marine riser.

[4] To be installed on top of the marine riser. The diverter system shall provide, as a minimum two 15-centimer (6-inch) internal diameter lines and full-opening valves.

[5] When a tapered drill string is in use, the BOP stack shall be equipped with one of the following pipe ram configurations:

a. Two (2) sets of pipe rams for the larger size string and one (1) set for the smaller size string of drill pipe.

b. Two (2) sets of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

c. Two (2) sets of variable bore pipe rams to fit both sizes of pipe.

d. One (1) set of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

e. One (1) set of pipe rams for the larger size string, one (1) set of pipe rams for the smaller pipe, and one (1) set of variable bore pipe rams to fit both sizes of pipe.

[1] The diverter system shall include a minimum of two 15-centimeter (6-inch) internal diameter lines and full-opening valves. The flowpath from the BOP to the branch point of diverter lines in new systems shall have a minimum internal diameter of 15 centimeters (6 inches).

[2] When a tapered drill string is in use, the BOP stack shall be equipped with one of the following pipe ram configurations:

a. Two (2) sets of pipe rams for the larger size string and one (1) set for the smaller size string of drill pipe.

b. Two (2) sets of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

c. Two (2) sets of variable bore pipe rams to fit both sizes of pipe.

d. Two (2) sets of pipe rams for the larger size string. The blind ram cavity shall be equipped with blind shear rams and the blind ram actuator shall be converted to operate the blind shear rams. A crossover sub to the larger size pipe shall be readily available on the rig floor.

e. One (1) set of pipe rams for the larger size string and one (1) set of variable bore pipe rams to fit both sizes of pipe.

f. One (1) set of pipe rams for the larger size string, one (1) set of pipe rams for the smaller pipe, and one (1) set of variable bore pipe rams to fit both sizes of pipe.

pertinent information, including seismic and geologic data, water depth, drilling-fluid hydrostatic pressure, a schematic diagram indicating the equipment to be installed from the rotary table to the proposed conductor-casing seat, and a contingency plan for moving off location.

5.5 *Conductor Casing.* Before drilling below this string, at least one remote-controlled, annular-type blowout preventer shall be installed. A diverter system and other equipment for circulating the drilling fluid to the drilling structure or vessel shall be installed as described in subparagraph 5.4.1.

5.6 *Surface and Intermediate Casing.* Before drilling below these strings, the blowout-preventer system shall consist of at least four remote-controlled, hydraulically operated blowout preventers including at least two equipped with pipe rams, one with blind rams, and one annular type. Subsea blowout-preventer stacks used with floating drilling vessels shall include one set of blind shear rams.

5.7 *Testing of BOP Systems.* Prior to conducting high-pressure tests, all BOPs shall be tested to a low pressure of 1,400 to 2,000 kPa (203 to 290 psi). All BOP tests shall be recorded in the driller's report.

5.7.1 *BOP Testing Frequency.* Surface and subsea BOP stacks shall be tested as follows:

a. When installed.

b. Before drilling out after each string of casing has been set.

c. At least once each week, but not exceeding 7 days between tests, alternating between control stations. If either control system is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between blowout-preventer tests is allowed when well operations prevent testing and remedial efforts are being performed, provided the tests will be conducted as soon as possible before normal operations resume, and the reason for postponing testing is entered into the log. Well operations which prevent testing are stuck drill pipe and pressure-control operations. Testing shall be at staggered intervals to allow each drilling crew to operate the equipment.

The weekly test is not required for blind and blind shear rams. These rams need only be tested prior to drilling out after each casing string has been set.

d. Following repairs that require disconnecting a pressure seal in the assembly.

5.7.2 *Pressure Testing Surface BOP Systems.* Ram-type BOPs and related control equipment including the choke manifold shall be tested at the anticipated surface pressure or at 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser. The annular-type BOP shall be tested at 70 percent of its rated working pressure or 70 percent of the minimum internal yield pressure of the casing, whichever is the lesser.

5.7.3 *Pressure Testing Subsea BOP Systems.* Subsea BOPs and all related well-control equipment shall be stump tested at the surface with water to the anticipated surface pressure, except that the annular-type BOP shall not be tested above 70 percent of its rated working pressure. After the installation of the BOP stack on the seafloor, the control equipment and ram-type BOPs shall be tested as required under subparagraph 5.7.2.

5.7.4 *Actuation of Auxiliary Well-Control Equipment.* In conjunction with the weekly pressure test of surface and subsea BOP systems, auxiliary well-control equipment such as choke manifold valves, kelly cocks, and drill pipe safety valves shall be actuated. Casing safety valves shall be actuated prior to running casing.

5.8 *Inspection and Maintenance.* All BOP systems, marine risers, and associated equipment shall be inspected and maintained to assure that the equipment will function properly. The manufacturers' recommended inspection and maintenance procedures are acceptable as guidelines in complying with this requirement. The BOP systems and marine risers shall be visually inspected at least once each day if the weather and sea conditions permit the inspection. Inspection of subsea installations may be accomplished by the use of television equipment.

5.9 *Blowout-Preventer Drills.* All drilling personnel shall be indoctrinated in blowout-preventer drills and be familiar with the blowout-preventer equipment before starting work on the well. A blowout-preventer drill shall be conducted for each drilling crew in accordance with the well-control drill requirements of the U.S. Geological Survey (USGS) Outer Continental Shelf Standard "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T1), First Edition, December 1977, or subsequent revisions thereto. A BOP drill may be required by a USGS designated representative at any time during the drilling operation, after notifying and consulting with the lessee's senior representative present.

All BOP drills shall be recorded in the driller's report.

6. *Mud Program.* The characteristics, use, and testing of drilling mud and the implementation of related drilling procedures shall be designed to prevent the loss of well control. Sufficient quantities of mud materials shall be maintained readily accessible for use at all times to assure well control.

Mud temperatures shall be controlled to minimize heat loss to the permafrost and to minimize thawing of the permafrost which can result in serious well problems while drilling through the permafrost. To insure maximum safety, hydrate zones shall be anticipated and diagnosed quickly, and drilled using the latest state-of-the-art methods. Provided that the hydrate zones are adequately protected, drilling can continue on a site specific basis without the need to cool the mud thereafter.

6.1 *Mud Control.* Before starting out of the hole with drill pipe, the mud shall be properly conditioned. Proper conditioning requires either circulation with the drill pipe just off bottom to the extent that the annular volume is displaced, or proper documentation in the driller's report prior to pulling the drill pipe as follows:

a. there is no indication of influx of formation fluids prior to starting to pull the drill pipe from the hole.

b. The weight of the returning mud is essentially the same as the weight of the mud entering the hole. In the event that the returning mud is lighter than the entering mud by a weight differential equal to or greater than 0.2 pound per gallon, the mud shall be circulated until the annular volume is displaced, and the mud properties shall be checked for the influx of gas or liquid.

c. Other mud properties recorded on the daily drilling log are within the specified ranges required by the mud program.

When the mud in the hole is circulated, the driller's report shall be so noted.

When coming out of the hole with drill pipe, the annulus shall be filled with mud before the change in mud level decreases the hydrostatic pressure 517 kPa (75 psi) or every 5 stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. The number of stands of drill pipe and drill collars that may be pulled prior to filling the hole and the equivalent mud volume shall be calculated and posted. A mechanical, volumetric, or electronic device for measuring the amount of mud required to fill the hole shall be utilized.

When there is an indication of swabbing or influx of formation fluids, the necessary safety devices and action shall be employed to control the well. The mud shall be circulated and

conditioned, on or near bottom, unless well or mud conditions prevent running the drill pipe back to the bottom.

For each casing string, the maximum pressure to be contained under the blowout preventer, before controlling excess pressure by bleeding through the choke, shall be posted near the driller's control console.

An operable gas separator shall be installed in the mud system prior to commencement of drilling operations. The separator shall be maintained for use throughout the drilling and completion of the well.

The mud in the hole shall be circulated or reverse-circulated prior to pulling the drill-stem test tools from the hole.

6.2 *Mud Testing and Monitoring Equipment.* Mud-testing equipment shall be maintained on the drilling rig at all times, and mud tests shall be performed once each tour, or more frequently, as conditions warrant. Such tests shall be conducted in accordance with procedures outlined in "API Recommended Practice for Standard Procedure for Testing Drilling Fluids," API RP 13B, Seventh Edition, April 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. The results of the tests shall be recorded and maintained at the drill site.

The following mud-system monitoring equipment shall be installed with derrick floor indicators and used when mud returns are established and throughout subsequent drilling operations:

a. Recording mud pit level indicator to determine mud pit volume gains and losses. This indicator shall include both a visual and an audio warning device.

b. Mud-volume measuring device for accurately determining mud volumes required to fill the hole on trips.

c. Mud-return indicator to determine that returns essentially equal the pump discharge rate.

d. Gas-detecting equipment to monitor the drilling mud returns, with indicators located in the mud-logging compartment or on the derrick floor. If the indicators are in the mud-logging compartment, there shall be a means of immediate communication with the rig floor, and the equipment shall be continually manned.

6.3 *Mud Quantities.* The lessee shall include, with his Application for Permit to Drill, a tabulation of well depth versus minimum quantities of mud material, including weighting material, to be maintained at the drill site to assure well control.

When the mud quantity required exceeds the storage capacity of the drilling facility, the lessee shall maintain maximum mud inventories and must receive approval from the District Supervisor of the lessee's plans to resupply mud inventories in the event of an emergency. The plan shall include an estimate of the time required for delivery of the mud supplies.

Daily inventories of mud materials, including weighting material, shall be recorded and maintained at the well site. Drilling operations shall be suspended in the absence of minimum quantities of mud material specified in the table or as modified in the approved plan.

6.4 *Safety Precautions in Enclosed Mud-Handling Areas.* All enclosed mud-handling areas where dangerous concentrations of combustible gases may accumulate shall be equipped with a ventilation system and with gas monitors. These enclosed areas shall be:

a. Ventilated with high-capacity mechanical ventilation systems capable of changing the air once every 2 minutes automatically on signal from a gas detector or gas detectors, that are operative at all times, indicating the presence of gas.

b. Maintained at a negative pressure relative to the surrounding areas where discharge to an adjacent enclosed area may be hazardous. The negative pressure areas are to be protected with a pressure sensitive alarm.

c. Fitted with gas detectors and alarms.

d. Equipped with electrical equipment of the "explosion proof" type. Alternatively, the equipment may be pressurized to prevent the ingress of explosive gases, and where air is used for pressurizing, the air intake shall be located outside of, and as far as practicable from, hazardous areas.

7. *Supervision, Surveillance, and Training.*

7.1 *Supervision.* A representative of the lessee shall provide onsite supervision of drilling operations on a 24-hour basis.

7.2 *Surveillance.* From the time drilling operations are initiated and until the well is completed or abandoned, a member of the drilling crew or the toolpusher shall maintain rig-floor surveillance continuously, unless the well is secured with blowout preventers, bridge plugs, storm packer, or cement plugs.

7.3 *Training.* Prior to conducting any drilling operations, lessee and drilling contractor personnel shall be trained and qualified in accordance with the provisions of the USGS Outer Continental Shelf Standard "Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations," No. T 1 (GSS–OCS–T 1), First Edition, December 1977, or subsequent revisions thereto.

In order to maintain qualification, any driller, toolpusher, or operator's representative, shall successfully complete a USGS-approved refresher course annually and repeat the basic well-control course every 4 years, as described in the provisions of GSS–OCS–T 1. Credit for these courses shall be obtained from USGS-approved schools. The refresher course shall be completed within 45 days of the student's anniversary date. The anniversary date is established upon the student's successful completion of a basic course in well control.

Records shall be maintained at the drill site for the affected personnel, indicating the specific training and refresher courses successfully completed, the dates of completion, and the names and dates of the courses.

In those areas which are subject to subfreezing conditions, the lessee shall ensure that personnel responsible for maintenance of the blowout-preventer stack, the associated-control equipment, and the hydraulic-control fluids shall be instructed in the proper procedures to prevent freezing of the hydraulic-control fluids in the control system and the fluids in the choke and kill lines.

8. *Hydrogen Sulfide.* When drilling operations are planned which will penetrate reservoirs known or expected to contain hydrogen sulfide (H_2S), or in those areas where the presence of H_2S is unknown, or upon encountering H_2S, the preventive measures and the operating practices set forth in USGS Outer Continental Shelf Standard "Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment," No. 1 (GSS–OCS–1), First Edition, February 1976, or subsequent revisions thereto, shall be followed.

9. *Critical Operations and Curtailment Plans.* Certain operations performed in drilling are more critical than others with respect to well control, and for the prevention of fire, explosion, oil spills, and other discharges or emissions. The lessee shall submit with the Exploration Plan or Development and Production Plan a Critical Operations and Curtailment Plan to be followed while conducting drilling operations on each lease. This plan shall include:

a. A list or description of the critical drilling operations that are, or are likely to be, conducted on the lease. This list or description shall specify the operations to be ceased, limited, or not to be commenced under given

circumstances or conditions. This list shall include operations such as:

(1) Drilling in close proximity to another well.

(2) Drill-stem testing.

(3) Running and cementing casing.

(4) Cutting and recovering casing.

(5) Logging or wireline operations.

(6) Well-completion operations.

(7) Moving the drilling vessel off location in an emergency, repositioning the vessel on location, and reestablishing entry into the well.

b. A list or description of circumstances or conditions under which such critical operations shall be curtailed. This list or description shall be developed from all the factors and conditions relating to the conduct of operations on the lease, and shall consider but not necesarily be limited to the following:

(1) Whether the drilling operations are to be conducted from mobile or fixed platforms.

(2) The availability and capability of containment and cleanup equipment and spill-control system response time.

(3) Abnormal or unusual conditions expected to be encountered during drilling operations.

(4) Known or anticipated meteorological, oceanographic, and ice conditions.

(5) Availability of personnel and equipment for particular operations to be conducted.

(6) Other factors peculiar to the particular lease under consideration.

c. The name of the person who has responsibility as the person-in-charge of overall drilling operations.

When any circumstance or condition listed or described in the plan occurs or other operational limits are encountered, the lessee shall notify the District Supervisor and shall curtail the critical operations as set forth under 9a.

Deviations from the plan shall require prior approval of the District Supervisor. If emergency action requires deviation from the plan, the District Supervisor shall be notified as soon as possible. The lessee shall review the plan at least annually. The lessee shall notify the District Supervisor of the results of this review. Any amendments or modifications of the plan are subject to the approval of the District Supervisor.

10. *Field Drilling Rules.* When sufficient geological and engineering information is obtained as a result of drilling operations, the lessee may make an application or the DCM, Offshore Field Operations, may require an application for the establishment of field drilling rules. After field drilling rules have been established by the DCM, Offshore Field Operations, development wells shall be drilled in accordance with these rules and the requirements of this Order which are not affected by such rules.

11. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior, Geological Survey Conservation Division

Alaska Region, Arctic

OCS Order No. 3

Effective————

Plugging and Abandonment of Wells

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.15 and 250.92. The lessee shall comply with the following minimum plugging and abandonment procedures which have general application to all wells drilled for oil and gas. Plugging and abandonment operations shall not be commenced prior to obtaining approval from the appropriate District Supervisor. Oral or telegraphic approvals shall be in accordance with 30 CFR 250.13.

1. *Application for Approval to Abandon a Well.* In accordance with 30 CFR 250.92, the lessee shall submit for approval a Form 9–331, Sundry Notices and Reports on Wells, containing the following information:

1.1 *Notice of Intention to Abandon a Well.* A detailed statement of the proposed work for abandonment of any well. For all wells, the statement shall describe the proposed work (including, by depths, the kind, location, and length of plugs) and plans for mudding, cementing, shooting, testing, and removing casing, and other pertinent information. The statement as to a producible well shall set forth the reasons for abandonment, the amount and date of last production, and complete data from the last well test.

1.2 *Subsequent Report of Abandonment.* A detailed report of the manner in which the abandonment or plugging work was accomplished, including the nature and quantities of materials used in the plugging and the location and extent, by depths, of casing left in the well, and the volume of mud fluid used. If an attempt was made to cut and pull any casing string, a description of the methods used and results obtained must be included.

2. *Permanent Abandonment.*

2.1 *Isolation of Zones in Open Hole.* In uncased portions of wells, cement plugs shall be spaced to extend 30 meters (98 feet) below the bottom to 30 meters (98 feet) above the top of any oil, gas, and freshwater zones so as to isolate them in the strata in which they are found and to prevent them from escaping into other strata or the surface. The placement of additional cement plugs to prevent the migration of formation fluids in the well bore may be required by the District Supervisor.

2.2 *Isolation of Open Hole.* Where the is open hole below the casing, a cement plug shall be placed in the deepest casing string in accordance with "a" or "b" below. In the event lost circulation conditions have been experienced or are anticipated, a permanent-type bridge plug may be placed in accordance with "c" below:

a. A cement plug set by the displacement method so as to extend a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the casing shoe.

b. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the casing shoe, with a cement plug calculated to extend at least 30 meters (98 feet) below the casing shoe and 15 meters (49 feet) above the retainer.

c. A permanent-type bridge plug set within 45 meters (148 feet) above the casing shoe with 15 meters (49 feet) of cement on top of the bridge plug. This bridge plug shall be tested in accordance with subparagraph 2.7 prior to placing subsequent plugs.

2.3 *Plugging or Isolating Perforated Intervals.* A cement plug shall be set by the displacement method opposite all open perforations (perforations not squeezed with cement) extending a minimum of 30 meters (98 feet) above and 30 meters (98 feet) below the perforated interval or down to a casing plug, whichever is less. In lieu of setting a cement plug by the displacement method, the following two methods are acceptable, provided the perforations are isolated from the hole below:

a. A cement retainer with effective back-pressure control set not less than 15 meters (49 feet) nor more than 30 meters (98 feet) above the top of the perforated interval with a cement plug calculated to extend at least 30 meters (98 feet) below the bottom of the perforated interval and 15 meters (49 feet) above the retainer.

b. A permanent-type bridge plug set within 45 meters (148 feet) above the top of the perforated interval with 15 meters (49 feet) of cement on top of the bridge plug.

2.4 *Plugging of Casing Stubs.* If casing is cut and recovered leaving a stub, one of the following methods shall be used to plug the casing stub:

2.4.1 *Stub Termination Inside Casing String.* A stub terminating inside a casing string shall be plugged by one of the following methods:

a. A cement plug set so as to extend 30 meters (98 feet) above 30 meters (98 feet) below the stub.

b. A cement retainer set 15 meters (49 feet) above the stub with a volume of cement equivalent to 45 meters (148 feet) squeezed below the retainer and with an additional 15 meters (49 feet) placed above the retainer.

c. A permanent bridge plug set 15 meters (49 feet) above the stub and capped with 15 meters (49 feet) of cement.

2.4.2 *Stub Termination Below Casing String.* If the stub is below the next larger string, plugging shall be accomplished in accordance with either subparagraph 2.1 or 2.2.

2.5 *Plugging of Annular Space.* Any annular space communicating with any open hole and extending to the ocean floor shall be plugged with cement.

2.6 *Surface Plug.* A cement plug at least 45 meters (148 feet) in length, with the top of the plug 45 meters (148 feet) or less below the ocean floor, shall be placed in the smallest string of casing which extends to the ocean floor.

2.7 *Testing of Plugs.* The setting and location of the first plug below the surface plug shall be verified by one of the following methods:

a. By placing a minimum pipe weight of 6,800 kilograms (15,000 pounds) on the cement plug, cement retainer, or bridge plug. The cement placed above the bridge plug or retainer need not be tested.

b. By testing the plug with a minimum pump pressure of 6,9000 kPa (1,000 psi) with no more than a 10-percent pressure drop during a 15-minute period.

2.8 *Mud.* Each of the respective intervals of the hole between the various plugs shall be filled with mud fluid of sufficient density to exert hydrostatic pressure exceeding the greatest formation pressure encountered while drilling the intervals between the plugs. Fluid left in the hole adjacent to the permafrost zone shall have a freezing point below the temperature of the permafrost zone and shall be treated to minimize corrosion of the casing. Any oil base fluid left in the hole will require prior approval of the District Supervisor.

2.9 *Clearane of Location.* All casing, wellhead equipment, and piling shall be removed to a depth of at least 5 meters (16 feet) below the ocean floor, or to a depth approved by the District Supervisor after a review of data on the ocean bottom conditions. The lessee shall verify that the location has been cleared of all obstructions.

2.10 *Cement.* The cement used for cement plugs placed across the permafrost zones shall be designed to set before freezing and to have a low heat of hydration.

3. *Temporary Abandonment.* Any drilling well which is to be temporarily abandoned shall be mudded and cemented as required for permanent abandonment except for the requirements in subparagraphs 2.6 and 2.9. When a drilling well is temporarily abandoned, a bridge plug or a cement plug shall be set at the base of the deepest casing string. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole.

The lessee shall set a retrievable or permanent bridge plug, or a cement plug at least 30 meters (98 feet) in length in the casing between 5 and 60 meters (16 and 197 feet) below the ocean floor.

When a casing stub extends above the ocean floor, the lessee shall comply with the requirements of OCS Order No. 1, paragraph 4, "Identification of Subsea Objects."

4. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved.

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior Geological Survey Conservation Division

Alaska Region, Artic

OCS Order No. 4 Effective ————

Determination of Well Producibility

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.12. An OCS lease provides for extension beyond its primary term for as long as oil or gas may be produced from the lease in paying quantities. The term "paying quantities" as used herein means production of oil and gas in quantities sufficient to yield a return in excess of operating costs. An OCS lease may be maintained beyond the primary term, in the absence of actual production, when a suspension of production has been approved in accordance with 30 CFR 250.12.

1. *Application for Determination of Well Producibility.* An application shall be submitted to the District Supervisor for the determination of every new well's capability of producting until a well, drilled on the lease, has been determined to be capable of producing oil or gas in paying quantities. The application shall be submitted within 60 days after the drilling rig has been moved from the well.

2. *Criteria for the Determination of Well Producibility.* The Deputy Conservation Manager (DCM), Offshore Field Operations, shall prescribe which of the following criteria is to be used to determine the capability of a well to produce in paying quantities.

2.1 *Production Tests.* All tests must be witnessed by an authorized representative of the U.S. Geological Survey. Test data accompanied by the lessee's affidavit, or third-party test data, may be accepted in lieu of a witnessed test, provided approval is obtained from the District Supervisor prior to the performance of the test. All tests must conform to the following minimum requirements:

a. A production test for oil wells of at least 2 hours' duration following stabilization of flow.

b. A deliverability test for gas wells of at least 2 hours' duration following stabilization of flow or 4-point back-pressure test.

2.2 *Production Capability Determination.* When the District Supervisor determines that open hole evaluation data, such as wireline formation tests, drill stem tests, core data, and logs, have been demonstrated as reliable in a geologic area, such data may be considered as acceptable evidence that a well is capable of producing in paying quantities.

3. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved.
Robert L. Rioux,
Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior Geological Survey Conservation Division

Alaska Region, Artic

OCS Order No. 5

Effective———————

Production Safety Systems

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10 and 250.11 and in accordance with 30 CFR 250.30, 250.38, 250.45, and 250.46. The lessee shall be responsible for compliance with the requirements of this Order in the installation and operation of the production safety systems on all platforms and structures located on the leasehold including those facilities not operated or owned by the lessee. All applications for approval under the provisions of this Order shall be submitted to the District Supervisor.

This Order requires the lessee to submit plans, applications, reports, data, and other information. In all cases where the lessee(s) has(have) identified another party as designated lease operator in accordance with 30 CFR 250.31, and where the term "operator" is defined in accordance with 30 CFR 250.2(gg), the required information may be submitted by the designated lease operator.

1. *Use of Best Available and Safest Technologies (BAST).* The lessee is encouraged to continue the development of safety-system technology. As research and product improvement results in increased effectiveness of existing safety equipment or the development of new equipment systems, such equipment may be used and, if such technologies provide a significant cost effective incremental benefit to safety, health, or the environment, shall be required to be used if determined to be BAST.

Conformance to the standards, codes, and practices referenced in this Order will be considered to be the application of BAST. Specific equipment and procedures or systems not covered by standards, codes, or practices will be analyzed to determine if the failure of such would have a significant effect on safety, health, or the environment. If such are identified and until specific performance standards are developed or endorsed by the U.S. Geological Survey (USGS), the lessee shall submit such information necessary to indicate the use of BAST, the alternatives considered to the specific equipment or procedures, and the rationale why one alternative technology was considered in place of another. This analysis shall include a discussion of the costs involved in the use of such technology and the incremental benefits gained.

2. *Quality Assurance and Performance of Safety and Pollution-Prevention Equipment.* Safety and Pollution-Prevention Equipment (SPPE) shall conform to the following quality assurance standards:

a. American National Standards Institute/American Society of Mechanical Engineers Standard "Quality Assurance and Certification of Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME SPPE–1, latest edition with all addenda.

b. American National Standards Institute/American Society of Mechanical Engineers Standard "Accreditation of Testing Laboratories for Safety and Pollution Prevention Equipment Used in Offshore Oil and Gas Operations," ANSI/ASME–SPPE–2, latest edition with all addenda.

The aplicable SPPE components, and the applicable SPPE specifications are identified in subparagraph 3.2 and subparagraph 4.2.

3. *Subsurface-Safety Devices.*

3.1 *Installation.* All tubing installations open to hydrocarbon-bearing zones shall be equipped with a subsurface-safety device such as a Surface-Controlled Subsurface-Safety Valve (SCSSV), a Subsurface-Controlled Subsurface-Safety Valve (SSCSV), an injection valve, a tubing plug, or a tubular/annular subsurface-safety device, unless, after application and justification, the well is determined to be incapable of flowing. Criteria and procedural guidelines for the determination of the capability of a well to flow are established by and are available from the District Supervisor. The device shall be installed within 2 days after production is stabilized. The well shall be attended in the immediate vicinity of the well so that emergency actions may be taken, if necessary, while the well is open to flow from a hydrocarbon-bearing zone, until a subsurface-safety device is installed.

In non-permafrost areas, the device shall be installed at a depth of 30 meters (98 feet) or more below the ocean floor. In permafrost areas, the setting depth of the subsurface-safety device shall be approved by the District Supervisor on a case-by-case basis.

3.1.1 *Subsurface-Safety Valves.* All tubing installations shall be equipped with a surface-controlled, or other remotely controlled, subsurface-safety device. Alternatives to this requirement may be approved by the Deputy Conservation Manager (DCM), Offshore Field Operations, when greater reliability or safety can be demonstrated.

3.2 *Specification for Subsurface-Safety Valves.* Surface-controlled and subsurface-controlled subsurface-safety valves required by subparagraphs 3.4 and 3.5, which are installed or replaced, shall conform to "American Petroleum Institute (API) Specification for Subsurface-Safety Valves," API Spec 14A, Fourth Edition, November 1979, with the exception of section 6, Appendix A and Appendix J of this specification, except for specific provisions thereof that are required in sections 1 through 5 of this specification, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use at the time of installation. The API monogram is optional, whereas the requirement for the OCS symbol is mandatory. A valve qualified to a previous edition of API Spec 14A is acceptable provided that the valve enters inventory within 3 years of its qualifying performance test date.

For purposes of this requirement, the term "replacement" is defined as occurring when that portion of the valve assembly containing the serial number is removed from inventory and a new certified valve is placed in inventory.

3.3 *Design, Installation, and Operation.* Subsurface-safety devices shall be designed, adjusted, installed, and maintained to insure reliable operation. During testing and inspection procedures, the well shall not be left unattended while open to production unless a properly operating subsurface-safety device has been installed in the well.

3.4 *Surface-Controlled Subsurface-Safety Valves.* All tubing installations open to a hydrocarbon-bearing zone shall be equipped with a surface-controlled subsurface-safety valve, except as specified in subparagraphs 3.1, 3.5, an 3.6. The surface controls may be located on the site or at a remote location.

The lessee shall furnish evidence that the surface-controled subsurface-safety devices and related equipment are capable of normal opeation under subfreezing conditions.

3.4.1. *Testing of Surface-Controlled Subsurface-Safety Valves.* Each surface-controlled, or other remotely controlled, subsurface-safety device installed in a well shall be tested in place for proper operation when installed or reinstalled and thereafter at intervals not exceeding 6 months. If the device does not operate properly, it shall be removed, repaired,

reinstalled or replaced, and tested to insure proper operation.

3.5 *Subsurface-Controlled Subsurface-Safety Valves.* Tubing installations in wells completed from single-well or multiwell satellite caissons or ocean floor completions may be equipped with a subsurface-controlled subsurface-safety valve in lieu of a surface-controlled, or other remotely controlled, subsurface-safety valve.

3.5.1 *Inspection and Maintenance of Subsurface-Controlled Subsurface-Safety Valves.* Each subsurface-controlled subsurface-safety valve installed in a well shall be removed, inspected, and repaired or adjusted as necessary and reinstalled at intervals not exceeding:

(1) 6 months for those valves not installed in a landing nipple.

(2) 12 months for those valves installed in a landing nipple.

3.6 *Tubing Plugs in Shut-in Wells.* A tubing plug shall be installed in lieu of, or in addition to, other subsurface-safety devices if a well has been shut-in for a period of 6 months. In nonpermafrost areas, tubing plugs shall be set at a depth of 30 meters (98 feet) or more below the ocean floor. In permafrost areas, each tubing-plug installation shall be approved by the District Supervisor on a case-by-case basis. All tubing plugs installed shall be of the pump-through type. All wells perforated and completed but not placed on production shall be equipped with a subsurface-safety valve or tubing plug within 2 days after completion. A surface-controlled subsurface-safety valve of the pump-through type may be used as a pump-through tubing plug for the purpose of this subparagraph: *Provided,* The surface control has been rendered inoperative. A shut-in well which is equipped with a tubing plug shall be inspected for leakage by opening the well to possible flow at intervals not exceeding 6 months. If a liquid leakage rate in excess of 400 cc/min or a gas leakage rate in excess of 7 dm^3/sec (15 cubic ft/min) is observed, the plug shall be removed, repaired, and reinstalled, or an additional tubing plug may be installed in lieu of removal and repair.

3.7 *Injection Wells.* A surface-controlled subsurface-safety valve or an injection valve capable of preventing backflow shall be installed in all wells placed in injection service.

Surface-controlled subsurface-safety valves shall be tested in accordance with subparagraph 3.4.1. Injection valves shall be tested in the manner as outlined for testing tubing plugs in subparagraph 3.6.

These requirements are not applicable if the District Supervisor concurs that the well is incapable of flowing. The lessee shall verify the no-flow condition of the well annually and submit an annual report certifying the no-flow status of the well.

3.8 *Temporary Removal for Routine Operations.* Each wireline- or pumpdown-retrievable subsurface-safety device may be removed, without further authorization or notice, for a routine operation which does not require the approval of a Sundry Notice and Report on Wells (Form 9–331) for a period not to exceed 15 days. The well shall be identified by a sign on the wellhead stating that the subsurface-safety device has been removed. The removal of the subsurface-safety device shall be noted in the records as required by subparagraph 3.11g. The well shall be attended in the immediate vicinity of the well so that emergency actions may be taken, if necessary, while the well is open to flow from a hydrocarbon-bearing zone until the subsurface-safety device is reinstalled, unless attendance has been waived by the District Supervisor. The well shall not be open to flow while the subsurface-safety device is removed except when flowing the well is necessary for that particular operation.

The provisions of this paragraph are not applicable to the testing and inspection procedures in subparagraphs 3.4.1, 3.5.1, 3.6, and 3.7.

3.9 *Additional Safety Equipment.* All tubing installations in which a wireline- or pumpdown-retrievable subsurface-safety device is installed shall be equipped with a landing nipple, with flow couplings or other protective equipment above and below, to provide for the setting of the subsurface-safety valve. The control system for all surface-controlled subsurface-safety valves shall be an integral part of the platform Emergency Shutdown System (ESD) as defined in Appendix C, Section C1 of "API Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface-Safety Systems on Offshore Production Platforms," API RP 14C, Second Edition, January 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. In addition to the activation of the ESD system by manual action on the platform, the system may be activated by a signal from a remote location. Surface-controlled subsurface-safety valves shall close in response to shut-in signals from the ESD system or the fire loop, or both.

3.10 *Emergency Action.* All tubing installations open to hydrocarbon-bearing zones and capable of flowing in which the subsurface-safety device has been removed, in accordance with the provisions of this Order, shall be identified by a sign on the well-head stating that the subsurface-safety device has been removed. A subsurface-safety device shall be available for each well on the platform. In the event of an emergency such as an impending storm, this device shall be properly installed as soon as possible with due consideration being given to personnel safety.

3.11 *Records.* The lessee shall maintain records for a minimum period of 5 years for each subsurface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the USGS. The records to be maintained shall contain verification of:

a. The manufacturer's design, including make, model, and type. For subsurface-controlled valves, number of the spacers, size of beans, springs, and the pressure settings.

b. The devices having been manufactured in accordance with the quality-assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as required by paragraph 2.

c. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SPPE–1.

d. The record of all configuration modifications to the certified design.

e. Installation at the required setting depth and in accordance with the manufacturer's instructions.

f. The identity of the personnel qualified in accordance with subparagraph 5.7 who directed all installations and removals.

g. The results of tests required by this Order, the dates of removals and reinstallations, and the reasons for removals and reinstallations.

h. The completion and submission of all failure reports required by paragraph 5 and all investigation reports required by paragraphs OE–2529 and OE–2670 of ANSI/ASME–SPPE–1.

3.12 *Reports.* Well completion reports (Form 9–330) and any subsequent reports of workover (Form 9–331) shall include the manufacturer, the type, and the installed depth of the subsurface-safety devices.

4. *Design, Installation, and Operation of Surface Production Safety Systems.*

All production facilities, including separators, treaters, compressors, headers, and flowlines, shall be designed, installed, and maintained in a manner which will facilitate an efficient, safe, and pollution-free operation.

The lessee shall furnish evidence that the surface-safety system and related equipment are capable of normal operation under subfreezing conditions, and that all equipment and operating procedures take into account floating ice, icing, and other extreme environmental conditions that may occur in the area.

4.1 *New Platforms.* New platform production facilities shall be protected with a basic and ancillary surface-safety system designed, analyzed, tested, and maintained in operating condition in accordance with the provisions of API RP 14 C, except Section A9, "Pipelines," which will be covered under OCS Order No. 9, and the additional requirements of Order No. 5. For this application, the word "should" contained in API RP 14 C shall be read "shall," except for those contained in explanatory statements, sections 3.4c and 4.3a(4)(a)–(f). If processing components are to be utilized, other than those for which Safety Analysis Checklists (SAC's) are included in API RP 14C, the analysis technique and documentation specified therein shall be utilized to determine the effects and requirements of these components upon the safety system.

4.2 *Specification for Wellhead Surface-Safety Valves.* All wellhead Surface-Safety Valves (SSV's) required by subparagraph 4.1 shall conform to "API Specification for Wellhead Surface Safety Valves for Offshore Service," API Spec 14D, Third Edition, November 1980, with the exception of Appendix A and Appendix J of this specification, except for specific provisions thereof that are required in sections 1 through 5 of this specification, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use at the time of installation. The API monogram is optional, whereas the requirement for the OCS symbol is mandatory.

4.3 *Submittal of Safety-System Design and Installation Features.* Prior to installation, the lessee shall submit for approval to the District Supervisor, in duplicate, information relative to design and installation features, as indicated in subparagraphs "a" through "g." This information shall also be maintained at the lessee's onshore field engineering office. All approvals are subject to field verifications. This information shall include:

a. A schematic flow diagram showing size, capacity, and design working pressure of separators, treaters, storage tanks, compressors, pipeline pumps, and metering devices.

b. A schematic flow diagram (reference API RP 14 C, example: figure E1) and the related Safety Analysis Function Evaluation (SAFE) chart (reference API RP 14C, Subsection 4.3c). These diagrams and charts shall be developed in accordance with the provisions of API RP 14C and the additional requirements of this Order.

c. A schematic piping diagram showing the size and maximum-allowable working pressure with reference to welding specification(s) or code(s) used. The maximum-allowable working pressures shall be determined in accordance with "API Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems," API RP 14E, First Edition, August 1975, and Supplement 2, October 1977, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. The recommendations contained in API RP 14E are acceptable for the design and installation of the platform piping system.

d. A diagram of the firefighting system.

e. Electrical system information including the following:

(1) A plan of each platform deck outlining any nonrestricted area, i.e., areas which are unclassified with respect to electrical equipment installations and outlining areas in which potential ignition sources, other than electrical, are to be installed. The area outline shall include the following information:

(a) Any surrounding production or other hydrocarbon source and a description of the deck, overhead, and firewall.

(b) Location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the wiring method, including the identification of each wire and cable type that is utilized.

(2) Elementary electrical schematic of any platform safety-shutdown system with a functional legend.

(3) Classification of areas for electrical installations in accordance with the National Electrical Code, 1978 Edition, and with the "API Recommended Practice for Classification of Areas for Electrical Installations at Drilling Rigs and Production Facilities on Lands and on Marine Fixed and Mobile Platforms," API RP 500B, Second Edition, July 1973, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

f. The design and schematics of the installation and maintenance of all fire and gas detection systems shall include the following:

(1) Type, location, and number of detection heads.

(2) Type and kind of alarm, including emergency equipment to be activated.

(3) Method used for detection.

(4) Method and frequency of calibration.

(5) Name of organization to perform system inspection and calibration.

(6) A functional block diagram of the detection system, including the electric power supply.

g. Certification that the design for the mechanical and electrical systems to be installed was approved by registered professional engineers. After these systems are installed, the lessee shall submit a statement to the District Supervisor certifying that the new installations conform to the approved designs or the lessee shall request approval of the "As-Built" changes.

5. *Additional Safety and Pollution-Control Requirements.* The following requirements modify or are in addition to those contained in API RP 14C.

5.1 *Design, Installation, and Operation.*

5.1.1 *Pressure Vessels.* Unless otherwise qualified for use according to subparagraph 5.1.1d below, pressure vessels shall be designed, fabricated, stamped, and maintained in accordance with specific sections of the ASME Boiler and Pressure Vessel Code as listed below. The pressure vessels shall conform to the July 1, 1977, edition of the Code or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

a. Pressure-relief valves shall be designed, installed, and maintained in accordance with applicable provisions of sections I, IV, and VIII. The relief valves shall conform to the valve-sizing and pressure-relieving requirements specified in these documents; however, the relief valves shall be set no higher than the maximum-allowable working pressure of the vessel. All relief valves and vents shall be piped in such a way as to prevent fluid from striking personnel or ignition sources.

b. Steam generators shall be equipped with Level Safety Low controls (LSL) in accordance with applicable provisions of sections I and IV.

c. The lessee shall determine, by the use of pressure recorders, the operating pressure ranges of all pressure-operated vessels in order to establish the pressure-sensor settings. Current

pressure-recorder charts shall be maintained at the nearest offshore field office. The high-pressure shut-in sensor shall be set no higher than 10 percent above the highest operating pressure of the vessel. This setting shall also be sufficiently below the relief valve's set pressure to assure that the pressure source is shut in before the relief valve starts relieving. The low-pressure shut-in pressure-sensor setting shall be no lower than 15 percent or 35 kilopascals (kPa) (5 psi), whichever is greater, below the lowest pressure in the operating range. The pressure-sensor setting of low-pressure sensors on pressure vessels which operate at less than 35 kilopascals (kPa) (5 psi) shall be approved by the District Supervisor on a case-by-case basis.

d. All pressure or fired vessels used in the production of oil or gas shall conform to the requirements stipulated in the edition of the ASME Boiler and Pressure Vessel Code, sections I, IV, and VIII, as appropriate, in effect at the time the vessel is ordered. Uncoded vessels shall be hydrostatically tested to a pressure 1.5 times their working pressures prior to placing in service. The test date, test pressure, and working pressure shall be marked on the vessel in a prominent place. A record of the test shall be maintained by the lessee in the field area.

5.1.2 *Flowlines.*

a. All flowlines from wells shall be equipped with high- and low-pressure shut-in sensors located in accordance with Section A1 and Figure A1 of API RP 14 C. The lessee shall determine, by the use of pressure recorders, the operating pressure ranges of flowlines in order to establish pressure-sensor settings. Current pressure-recorder charts shall be maintained at the nearest offshore field office.

The high-pressure shut-in sensor(s) shall be set no higher than 10 percent above the highest operating pressure of the line; but, in all cases, it shall be set sufficiently below the maximum shut-in wellhead pressure or the gas-lift supply pressure to assure actuation of the surface-safety valve. The low-pressure shut-in sensor(s) shall be set no lower than 10 percent or 35 kPa (5 psi), whichever is greater, below the lowest operating pressure of the line in which it is installed.

b. If a well flows directly to the pipeline before separation, the flowline and valves from the well located upstream of, and including, the header inlet valve(s) shall have a working pressure equal to or greater than the maximum shut-in pressure of the well, unless the flowline is protected by one of the following:

(1) A relief valve which vents into the platform flare scrubber or some other location approved by the District Supervisor.

(2) An additional automatic shutdown valve controlled by an independent high-pressure sensor. The platform flare scrubber shall be designed to handle, without liquid-huydrocarbon carryover to the flare, the maximum-anticipated flow of liquid-hydrocarbons which may be relieved to the vessel.

5.1.3 *Pressure Sensors.* Pressure sensors may be of the automatic- or nonautomatic-reset type. When the automatic-reset types are used, a nonautomatic-reset relay shall be installed. All pressure sensors shall be equipped to permit testing with an external pressure source.

5.1.4 *Emergency Shutdown System.* The manually operated ESD valve shall be quick-opening and nonrestricted to enable the rapid actuation of the shutdown system. ESD stations may utilize a loop of breakable synthetic tubing in lieu of a valve only at the boat landing.

On an emergency shutdown, the Surface-Controlled Subsurface-Safety Valve (SCSSV) shall close in not more than 2 minutes after the shut-in signal has closed the surface safety valve (SSV). Design delayed closure time greater than 2 minutes shall be justified by the lessee based on the individual well's mechanical/production characteristics and approved by the District Supervisor.

Electro-pneumatic systems shall meet the corresponding design and functional requirements as those which apply to pneumatic systems.

A schematic of the ESD system which indicates the control functions of all safety devices shall be maintained on the platform or nearest offshore field office.

5.1.5 *Engine Exhausts.* Engine exhausts shall be equipped to comply with the insulation and personnel-protection requirements of API RP 14C, Section 4.2c(4). Exhaust piping from diesel engines shall be equipped with spark arrestors.

5.1.6 *Glycol-Dehydration Units.* A pressure-relief system or an adequate vent shall be installed on the glycol regenerator, or at a location approved by the District Supervisor, which will prevent overpressurization of all glycol-dehydration units. The set pressure of the pressure-relief system shall be determined by the lessee and approved by the District Supervisor. The discharge of the relief valve shall be vented in a nonhazardous manner. The glycol-dehydration unit shall be properly maintained to prevent overpressurization of the unit.

5.1.7 *Gas Compressors.* Each compressor shall be equipped with the following protective equipment:

(1) A PSH, a PSL, a PSV, and an LSH to protect each interstage and suction scrubber.

(2) An LSL to protect each interstage and suction scrubber, unless the fluid is dumped through a choke restriction to another pressure vessel. An LSL shut-in control(s) installed in interstage and suction scrubber(s) may be designed to actuate the automatic shutdown valve(s) (SDV's) installed in the scrubber dump line(s).

(3) A TSH on each compressor cylinder or other components as applicable.

(4) In addition to the provisions of API RP 14C, Subsection A8.3, PSH and PSL shut-in sensors and LSH shut-in controls protecting compressor suction and interstage scrubbers shall be designed to actuate automatic SDV's located in each compressor suction and fuel gas line so that the compressor unit and the associated vessels can be isolated from all input sources.

All automatic SDV's installed in compressor suction and fuel gas piping shall also be actuated by the shutdown of the prime mover. Compressor installations of 745 kilowatts (1,000 horsepower) or less are excluded from those requirements of API RP 14C, A8.3d, which provide for installation of a blowdown valve (BDV) on the discharge line.

5.1.8 *Firefighting Systems.* Firefighting systems shall conform to Subsection 5.2, "Fire Water Systems," of "API Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms," API RP 14G, First Edition, September 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use, and the additional requirements of this subparagraph.

A firewater system consisting of rigid pipe with firehose stations shall be installed. The firewater system shall be installed to provide needed protection in all areas where production-handling equipment is located. A fixed water-spray system shall be installed in enclosed well-bay areas where hydrocarbon vapors and accumulate.

Acceptable pump drivers include diesel engines, natural gas engines, and electric motors. Fuel or power shall be available for at least 30 minutes of run-time during platform shut-in time. If necessary, an alternate fuel supply shall be installed to provide for this pump-operating time unless an alternate

firefighting system has been approved by the District Supervisor.

A firefighting system using chemicals may be used or may be required in lieu of a water system if the District Supervisor determines that the use of a chemical system provides equivalent fire protection control. A diagram of the firefighting system showing the location of all firefighting equipment shall be posted in a prominent place on the platform or structure.

5.1.9 *Fire and Gas Detection System.*

a. Fire (flame, heat, or smoke) sensors shall be used in all enclosed high-hazard areas. Gas sensors shall be used in all inadequately ventilated, enclosed, high-hazard areas. Adequate ventilation is as defined in API RP 14C, Appendix C, paragraph C1.3b.

b. All detection systems shall be capable of continuous monitoring. Fire detection systems and portions of combustible gas detection systems related to the higher gas concentration levels shall be of the manual-reset type. Combustible gas detection systems related to the lower gas concentration level may be of the automatic-reset type.

c. A fuel gas odorant or an automatic gas-detection and alarm system are required in enclosed, continuously manned areas of the facility.

d. The District Supervisor may require a gas detector or alarm in any potentially hazardous area.

e. Fire detection systems shall be of an approved type, designed and installed in accordance with the National Fire Protection Association Standard for Automatic Fire Detectors, No. 72E, 1974, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Gas detection systems shall be of an approved type, designed and installed in accordance with sections 9.1 and 9.2 of "API Recommended Practice For Design and Installation of Electrical Systems for Offshore Production Platforms," API RP 14F, First Edition, July 1978, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

5.1.10 *Electrical Equipment.* The following requirements shall be applicable to all electrical equipment and systems:

a. All engines with ignition systems shall be equipped with a low-tension ignition system of a low-fire-hazard type and shall be designed and maintained to minimize the release of sufficient electrical energy to cause ignition of an external, combustible mixture.

b. All electrical generators, motors, and lighting systems shall be installed, protected, and maintained in accordance with the edition of the National Electrical Code and API RP 500B in effect at the time of approval.

c. At the time of approval, wiring methods shall conform to the National Electrical Code, 1978 Edition, or to the Institute of Electrical and Electronic Engineers (IEEE) "Recommended Practice for Electric Installation on Shipboard," IEEE Std. 45–1977, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Each conductor of a wire, a cable, or a bus bar shall be made of copper on all installations.

d. The elementary electrical schematic of the platform safety-shutdown system required by subparagraph 4.3e(2) shall be maintained on the platform or structure. This schematic shall indicate the control functions of all electrically actuated safety devices.

e. Maintenance of these systems shall be by personnel who are familiar with the construction and operation of the equipment and the hazards involved.

f. An auxiliary power supply shall be installed to provide emergency power, capable of operating all electrical equipment required to maintain safety of operations, in the event of a failure in the primary electrical power supply. This requirement is not applicable to those systems, or portions of systems, which are designed to fail-safe.

5.1.11 *Erosion.* A program of erosion control shall be in effect for wells or fields having a history of sand production. The erosion-control program may include sand probes, X–ray, ultrasonic, or other satisfactory monitoring methods. An annual report, by lease, indicating the wells which have erosion-control programs in effect and the results of the programs shall be submitted by the first of December to the programs shall be submitted by the first of December to the USGS Conservation Manger in the appropriate Regional Office.

5.2 *General Platform Operations.*

a. Surface- or subsurface-safety devices shall not be bypassed or blocked out of service unless they are temporarily out of service for startup, maintenance, or testing procedures. Only the minimum number of safety devices necessary for the operation shall be taken out of service. Personnel shall monitor the bypassed or blocked-out functions. Any surface- or surface-safety device which is temporarily out of service shall be flagged.

b. When wells are disconnected from producing facilities and blind-flanged or equipped with a tubing plug, compliance is not required with the provisions of API RP 14C or this Order concerning:

(1) Installation of automatic fail-close SSV on wellhead assemblies.

(2) Installation of the PSH and the PSL shut-in sensors downstream of the choke in flowlines from wells.

(3) Installation of flow safety valves (FSV's) in header individual flowlines.

c. When pressure or atmospheric vessels are positively isolated from production facilities (for example, inlet valve locked closed or inlet line blind-flanged) and are to remain isolated for an extended period of time, safety device compliance is not required with API RP 14C or this Order.

d. All open-ended lines connected to producing facilities shall be plugged or blind-flanged, except those lines designed to be open-ended, such as flared or vent lines.

5.3 *Simultaneous Platform Operations.* Prior to conducting activites simultaneously with production operations which could increase the possibility of occurrence of undesirable events, such as harm to personnel or to the environment or damage to equipment, a "General Plan for Conducting Simultaneous Operations" in a producing field shall be filed for approval with the District Supervisor. This plan shall be modified and updated by supplemental plans when actual simultaneous operations are scheduled which are significantly different from those covered in the General Plan.

Activities requiring these plans are drilling, completion, workover, wireline, pumpdown, and major construction operations.

5.3.1 *General Plan.* The "General Plan for Conducting Simultaneous Operations" shall include:

a. A narrative description of operations.

b. Procedures for the mitigation of potentially undesirable events including:

(1) The guidelines the lessee will follow to assure coordination and control of simultaneous activities.

(2) The identity of the persons having overall responsibility at the site for the safety of platform operations.

5.3.2 *Supplemental Plan.* The "Supplemental Plan for Conducting Simultaneous Operations" shall include:

a. A floor plan of each platform deck indicating critical areas of simultaneous activities.

b. An outline of any additional safety measures that are required for simultaneous operations.

c. Specification of any added or special equipment or procedural conditions imposed when simultaneous activities are in progress.

5.4 *Welding and Burning Practices and Procedures.* The following requirements are applicable to any welding or burning practice or procedure performed on:

a. An offshore mobile-drilling unit during the drilling mode.

b. A mobile workover unit during any drilling, completion, recompletion, remedial, repair, stimulation, or other workover activity.

c. A platform, structure, artificial island, or other installation during any drilling, completion, workover, or production operation.

d. A platform, structure, artificial island, or other installation which contains a well open to a hydrocarbon-bearing zone.

For the purpose of this Order, the terms "welding" and "burning" are defined to include arc or acetylene cutting and arc or acetylene welding.

All offshore welding and burning shall be minimized by onshore fabrication when feasible.

5.4.1 *General Welding, Burning, and Hot Tapping Plan.* Each lessee shall file for approval by the District Supervisor a "Welding, Burning, and Hot Tapping Safe Practices and Procedures Plan." The plan shall include the qualification standards or requirements for personnel and the methods by which the lessee will assure that only personnel meeting such standards or requirements are utilized. A copy of this plan shall be available in the field area. Any person designated as a welding supervisor shall be thoroughly familiar with this plan. An approved plan is required prior to the conduct of any welding, burning or hot tapping operation. All welding and burning equipment shall be inspected prior to beginning any welding or burning. Welding machines located on production or process platforms shall be equipped with spark arrestors and drip pans. Welding leads shall be completely insulated and in good condition; oxygen and acetylene bottles secured in a safe place; and hoses leak-free and equipped with proper fittings, gauges, and regulators.

5.4.2 *Designated Safe-Welding and Burning Areas.* The lessee shall establish, if feasible, and so designate areas on the platform determined to be safe-welding areas pursuant to the National Fire Protection Association Bulletin "Cutting and Welding Processes," No. 51 B, 1976, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use. Approval for the use of such areas shall be obtained from the District Supervisor. These designated areas shall be identified in the General Plan and a drawing showing the location of these areas shall be maintained on the facility. Welding or burning performed in any other areas shall be performed in compliance with the procedures set forth in subparagraph 5.4.3.

5.4.3 *Undesignated Welding and Burning Areas.* All welding or burning which cannot be done in an approved safe-welding area shall be performed in compliance with the procedures outlined below:

a. Prior to the commencement of any welding or burning operation on a structure, the lessee's designated person-in-charge at the installation shall personally inspect the qualifications of the welder or welders to assure that they are properly qualified in accordance with the lessee-approved qualification standards or requirements for welders. The designated person-in-charge and the welders shall personally inspect the work area for potential fire and explosion hazards. After it has been determined that it is safe to proceed with the welding or burning operation, the designated person-in-charge shall issue a written authorization for the work.

b. During all welding and burning operations, one or more persons shall be designated as a Fire Watch. Persons assigned as a Fire Watch shall have no other duties while actual welding or burning operations are in progress. If welding is to be done in an area which is not equipped with a gas detector, the Fire Watch shall also maintain a continuous surveillance with a portable gas detector during welding.

c. Prior to any welding or burning operation, the Fire Watch shall have in his possession firefighting equipment in a usable condition. At the end of the welding operation, the equipment shall be returned to a usable condition.

d. No welding, other than approved hot tapping, shall be done on piping, containers, tanks, or other vessels which have contained a flammable substance unless the contents have been rendered inert and determined to be safe for welding or burning by the designated person-in-charge.

e. If drilling, workover, or wireline operations are in progress on the platform, welding operations in other than approved safe-welding areas shall not be conducted unless the well(s) where these operations are in progress contain noncombustible fluids and the entry of formation hydrocarbons into the wellbore is precluded. All other provisions of this section shall also be applicable.

f. If welding or burning operations are conducted in the well-bay or production area, all producing wells shall be shut in at the surface-safety valve.

5.5 *Safety Device Testing.* The safety-system devices which are required by this Order shall be tested by the lessee at the interval specified below or more frequently if operating conditions warrant.

Testing shall be in accordance with API RP 14C, appendix D, and the following:

a. All PSV's shall be tested for operation at least once every 12 months. these valves shall be either bench-tested or equipped to permit testing with an external pressure source.

b. All Pressure Sensors-High/Low (PSHL) shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

c. All SSV's shall be tested for operation and for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. the SSV's shall be tested for operation in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection L, and tested for leakage in accordance with subsection M. If the valve does not operate properly or any fluid flow is observed in step 3 of the leakage test, the valve shall be repaired or replaced.

d. All flowline FSV's shall be checked for leakage at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. The FSV's shall be tested for leakage in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2, subsection D. If the leakage measured in step 6 exceeds a liquid flow of 400 cc/min or a gas flow of 7dm³/sec (15 cubic ft/min), the FSV's shall be repaired or replaced.

e. All LSH and LSL controls shall be tested at least once each calendar month, but at no time shall more than 6 weeks elapse between tests. These tests shall be conducted by raising and lowering the liquid level across the level-control detector.

f. All automatic inlet SDV's which are actuated by a sensor on a vessel or a compressor shall be tested for operation at least once each calendar month, but at no time shall more than 6 weeks elapse between tests.

g. All SDV's located in liquid-discharge lines and actuated by vessel low-level sensors shall be tested for operation once each calendar month, but at no time shall more than 6 weeks elapse between tests.

h. the TSH shutdown controls installed on compressors in lieu of a PSH and PSL on interstage scrubbers

shall be tested every 6 months and repaired or replaced as necessary.

i. All pumps for firewater systems shall be inspected and test-operated weekly.

j. All fire (flame, heat, or smoke) and gas detection systems shall be tested for operation and recalibrated every 6 months.

k. The lessee shall notify the District Supervisor when the lessee is ready to conduct a preproduction test and inspection of the integrated safety system. The lessee shall also notify the District Supervisor upon commencement of production in order that a post-production test and inspection of the integrated system may be conducted.

l. All TSH devices on fired components shall be tested at least once every 12 months.

m. The ESD system shall be tested for operation at least once each calendar month but at no time shall more than 6 weeks elapse between tests. The test may be conducted by closing at least one SSV from each of the ESD stations.

5.6 *Records.* The lessee shall maintain records for a minimum period of 5 years for each surface-safety device installed. These records shall be maintained in the nearest offshore field office for a minimum period of 2 years. If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. These records shall be available for review by any authorized representative of the USGS. The records shall show the present status and history of each device, including dates and details of installation, inspection, testing, repairing, adjustments, and reinstallation.

5.6.1 *Surface-Safety Valve and Associated Actuator Records.* Records for surface-safety valves and associated actuators which require compliance with paragraph 2 shall contain additional information showing verification of:

a. The devices having been manufactured in accordance with the quality assurance requirements of ANSI/ASME–SPPE–1 (formerly ANSI/ASME–OCS–1) as required by paragraph 2.

b. The completion and return of the receiving report to the manufacturer as required by ANSI/ASME–SUPPE–1.

c. The completion and submission of all failure reports required by paragraph 6 and all investigation reports required by paragraph OE–2529 and OE–2670 of ANSI/ASME–SPPE–1.

5.7 *Safety Device Training.* Before January 1, 1982, the lessee shall ensure that all personnel engaged in installing, inspecting, testing, and maintaining these safety devices will have been qualified under a program as recommended by "API Recommended Practice for Qualification Programs for Offshore Production Personnel Who Work With Anti-Pollution Safety Devices," API RP T–2, revised October 1975, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use.

Documented evidence of the qualifications of individuals performing these functions shall be maintained in the field area.

Manufacturers' representatives need not be qualified in accordance with API RP T–2 if they are working on equipment supplied by their company, provided they have received training and are qualified by the manufacturer to install, service, or repair the specific safety device or safety system, and if they are directly supervised by an API RP T–2 qualified person who is capable of evaluating the impact of the work on the total system.

On-the-job trainees working with safety devices shall be directly supervised by a qualified person.

Before January 1, 1981, the lessee shall submit an application for approval to the Deputy Chief, Conservation Division—Offshore Minerals Regulation, describing the training to be conducted and the methods the lessee will utilize.

The application shall include:

a. A designation of the lessee's representative who is responsible for training and coordinating training matters with the USGS.

b. The categories of personnel to be qualified.

c. The training organizations and courses to be utilized.

d. The method for ensuring the qualification of third-party personnel.

e. The method for determining when additional training or requalification is required and the method for obtaining this training and requalification.

f. The method of monitoring operations to ensure that only qualified personnel perform certain functions.

g. The method of maintaining documented evidence of qualification at the work site.

6. *Failure and Inventory Reporting System (FIRS).* The USGS has established a safety and pollution-prevention device Failure and Inventory Reporting System (FIRS), to enhance the reliability and safety of operations in the OCS. This system applies to offshore structures, including satellites and jackets, which produce or process hydrocarbons and includes the attendant portions of hydrocarbon pipelines, when physically located on the structure.

When the devices specified herein are used as a part of the production safety and pollution-prevention system, the lessee shall:

a. Submit an initial inventory and periodic updates in accordance with the procedures described in subparagraph 6.1.3.

b. Report all device failures which occur. The report content and format shall be in accordance with the procedures described in subparagraph 6.1.4.

c. If the method of data submitted as described in subparagraph 6.1.1 is USGS Form 9–1994 and Form 9–1995, the lessee shall submit the original of the form to the USGS and retain the two copies. Inventory and failure data required by this Order shall be submitted to the USGS Conservation Manager in the appropriate Regional Office.

6.1. *Data and Reporting Requirements.*

6.1.1. *Format.* Inventory and failure data shall be submitted in a format containing the same information that is in the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report (Form 9–1995), and as outlined in the respective User's Instruction Booklets. Copies of the forms and booklets may be obtained from the USGS Conservation Manager in the appropriate Regional Office.

The specific method of submitting the required data may be selected from the following:

a. USGS Forms 9–1994 and 9–1995, using a standard coding convention (e.g., all letters capitalized, Z, I, letter O, number 0).

b. ADP card decks of standard 80-column cards.

c. Magnetic tapes which are 9-track, 800 BPI, unlabeled, blocking cannot exceed 1,040 characters, odd parity, single gap (i.e., compatible with IBM equipment EBCDIC).

Regardless of which method is used for submitting the inventory and failure data, a cover letter forwarding the data to the USGS shall contain the signature of the person initiating/approving the information contained therein.

When Form 9–1995 is used, the form shall contain in the lower right coner a signature of the person initiating/approving the report.

6.1.2. *Device Coverage.* Inventory and failure reports are to be submitted on the safety and pollution-prevention devices on offshore structures, including satellites and jackets, which produce or process hydrocarbons, and the

hydrocarbon pipelines thereon. These reports shall be submitted on the following devices:

a. Blowdown Vales (BDV)
b. Burner Flame detectors (BSL)
c. Check Valves (FSV)
d. Combustible Gas Detectors (ASH)
e. Emergency Shutdown Valves (ESD)
f. Level Sensors High (LSH); Low (LSL); Hi/Lo (LSHL)
g. Pressure Sensors High (PSH); Low (PSL); Hi-Lo (PSHL)
h. Relief Valves (PSV)
i. Shutdown Valves (SDV)
j. Subsurface-Safety Valves (SSSV)
k. Surface-Safety Valves (SSV)
l. Temperature Sensors High (TSH); Low (TSL); Hi/Lo (TSHL)
m. Valve Actuators on shutdown valves, blowdown valves, and surface-safety valves (VA)

6.1.3 *Device Inventory Reporting.*

6.1.3.1 *Initial Inventory.* A complete initial inventory of the active safety and pollution-prevention devices shall be submitted no later than 1 month after the initial platform production date.

6.1.3.2 *Inventory Updates.* An updating of or addition/deletion to the latest inventory shall be submitted on a monthly basis so as to maintain a current and accurate data base. The inventory will be updated by using the contents of the Safety Device Inventory Report (Form 9–1994) and the Safety Device Failure Report (Form 9–1995), as described in the FIRS Instruction Booklet.

Inventory updating due to the addition, deletion, or changeout of a device is accomplished *by the lessee* reporting all of the data required in the Safety Device Inventory Report (Form 9–1994). Whenever a device fails and is either replaced with a new device or "fixed" and put back into service, the inventory shall be updated to reflect this change. Inventory updating, due to the failure of a device, will be performed *by the USGS,* using the contents of the Safety Device Failure Report (Form 9–1995). Inventory updating information shall be received no later than 30 days following the month in which the device change was made.

6.1.3.3 *Inventory-Reporting Methods.* Inventory data shall be reported either on the Safety Device Inventory Reporting forms (Form 9–1994), punched cards, or magnetic tapes. The reports shall contain all of the required information in the standard format as described in subparagraph 6.1.1.

6.1.3.4 *Inventory Verification.* The device inventory shall be verified by the lessee to ensure that the inventory data base is maintained on a current basis and that changes are being incorporated as they occur. The verification shall be accomplished no more frequently than once each 6-month period. When verification is required, the USGS will provide the lessee with a copy of the information on record, in the lessee's selected reporting format. The lessee shall review the information and either submit a letter stating that the information is correct, or make the appropriate corrections to the information provided by the USGS. The letter or appropriate corrections shall be received no later than 30 days following the month in which the inventory information which is to be verified was forwarded to the lessee.

6.1.3.5 *Inventory-Reporting Deviation.* A lessee may submit an inventory, update, or verification report differing from that described in subparagraph 6.1.3 when authorized by the USGS.

6.1.4 *Device Failure Reporting.*

6.1.4.1 *Failure-Data Submittal.* The failure data, as defined in subparagraph 6.1.4.3, shall be received no later than 30 days following the month in which the failure was detected. These data must contain all of the required information and be submitted in the standard format either on Safety Device Failure Report forms (Form-9–1995), punched cards, or magnetic tape, as previously described in subparagraph 6.1.1. Information on the failed device must match that previously submitted in inventory reporting. A formal failure analysis is not required by this Order, but each failed device shall undergo sufficient test/disassembly to establish the basic cause(s) of the failure.

6.1.4.2 *Failure-Data Verification.* After receipt of the complete failure data from the lessees, the USGS will make a printout of all failures by manufacturer, model, and reported cause. Each manufacturer listed will be furnished a copy of the printout containing the reported failures of his devices only. If he disagrees with the reported failure causes, he is invited to investigate the questioned causes in coordination with the reporting lessee and provide a coordinated reply within 6 weeks after receipt of the printout. If no reply is received within that time period, the originally reported causes will be considered to be correct, and the data will be evaluated accordingly.

6.1.4.3 *Failure Definition.* The safety and pollution-prevention device Failure and Inventory Reporting System does not differentiate between a malfunction and a failure. For the purpose of this program, a failure is defined as the inability of a device to perform its designed function within specified limits. A device is considered to have failed if it does not operate properly (perform its function) as required within the specified test tolerances. Examples of device failures are included in the FIRS Instruction Booklet.

A failure report is not required for:

a. Adjustments made within specified tolerances.

b. Adjustments required due to changes in operating conditions.

6.2 *Records.* The lessee shall maintain FIRS data records for a minimum period of 5 years. Equipment failure records shall be maintained in the nearest offshore field office for a minimum period of 2 years. If the lessee has no such offshore field office, then the records shall be kept in the nearest onshore field office. The records may then be transferred to the onshore field office for the remaining 3 years of the 5-year retention period. The records shall be available for review by any authorized representative of the USGS.

7. *Crane Operations.* Cranes shall be operated and maintained in accordance with U.S. Coast Guard regulations.

8. *Employee Orientation and Motivation Programs for Personnel Working Offshore.* The lessee shall make a planned, continuing effort to eliminate accidents due to human error. This effort shall include the training of personnel in their functions. A program to achieve safe and pollution-free operations shall be established. This program shall include instructions in the provision of "API Recommended Practice Orientation Program for Personnel Going Offshore for the First Time," API RP T–1, January 1974, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Reguation, has approved for use. "API Employee Motivation Programs for Safety and Prevention of Pollution in Offshore Operations," API Bulletin T–5, September 1974, or subsequent revisions which the Deputy Chief, Conservation Division—Offshore Minerals Regulation, has approved for use shall be used as a guide in developing employee safety and pollution-prevention motivation programs.

9. *Requirements for Drilling Rigs.*

9.1 *Fixed Structures.* The following requirements contained in this Order are applicable to drilling rigs on fixed structures:

a. Paragraph 1, "Use of Best Available and Safest Technologies (BAST)."

b. Subparagraph 5.1.10, "Electrical Equipment."

c. Subparagraph 5.4, "Welding Practices and Procedures."

d. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

9.2 *Mobile Drilling Units.* The following requirements contained in this

Order are applicable to drilling rigs on mobile drilling units:

a. Paragraph 1, "Use of Best Available and Safest Technologies (BAST)."

b. Subparagraph 5.4, "Welding Practices and Procedures."

c. Paragraph 8, "Employee Orientation and Motivation Programs for Personnel Working Offshore."

10. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

United States Department of the Interior Geological Survey Conservation Division

Alaska Region—Arctic, OCS Order No. 7, Effective ————, Pollution Prevention and Control

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.43. The lessee shall comply with the following requirements:

1. *Pollution Prevention.* During the exploration, development, production, and transportation of oil and gas, the lessee shall prevent pollution of the ocean. Furthermore, by the disposal of waste materials into the ocean, the lessee shall not create conditions which will adversely affect the public health, life, property, aquatic life, wildlife, recreation, navigation, commercial fishing, or other uses of the ocean.

1.1 *Liquid Disposal.*

1.1.1 *Drilling-Mud Components.* The lessee shall submit, as a part of the Application for Permit to Drill (Form 9–331 C), a detailed list of drilling-mud components including the common chemical or chemical trade name of each component, a list of the drilling-mud additives anticipated for use in meeting special drilling requirements, and the proposed method of drilling-mud disposal. The disposal of drilling mud is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of drilling-mud disposal into the ocean shall be obtained from the District Supervisor; each request will be decided on a case-by-case basis.

1.1.2 *Hydrocarbon-Handling Equipment.* All hydrocarbon-handling equipment for testing and production such as separators, tanks, and treaters shall be designed and operated to prevent pollution. Maintenance or repairs which are necessary to prevent pollution of the ocean shall be undertaken immediately.

1.1.3 *Curbs, Gutters, and Drains for Fixed Platforms or Structures and Mobile Drilling Units.*

a. *Fixed Platforms, Structures, and Artificial Islands.* Curbs, gutters, drip pans, and drains shall be installed in all deck areas in a manner necessary to collect all contaminants and piped to a properly designed, operated, and maintained sump system which will automatically maintain the oil at a level sufficient to prevent discharge of oil into OCS waters. Sump piles shall not be used as processing devices to treat or skim liquids, but shall be used to collect treated produced water, treated sand, liquids from drip pans and deck drains, and as a final trap for hydrocarbon liquids in event of equipment upsets.

On artificial islands, all vessels containing hydrocarbons shall be placed inside an impervious berm. The volume enclosed by the berm shall be in excess of the volume of vessels containing hydrocarbons. In addition, the rig mat shall be made impervious, and all drainage ditches shall be directed away from the drilling rig to an impervious sump.

b. *Mobile Drilling Units.* Curbs, gutters, and drains which collect contaminants associated with the drilling operation on a mobile drilling unit shall be installed as required by subparagraph 1.1.3a. Curbs, gutters, and drains which collect contaminants not associated with the drilling operation are subject to regulation by the U.S. Coast Guard.

1.1.4 *Discharges from Fixed Platforms or Structures and Mobile Drilling Units.* Discharges from fixed platforms or structures and mobile drilling units, including sanitary waste, produced water, drilling mud, and deck drainage, are subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended.

1.2 *Solid Material Disposal.*

1.2.1 *Well Solids.* The disposal of drill cuttings, sand, and other well solids containing oil is subject to the Environmental Protection Agency's permitting procedures, pursuant to the Federal Water Pollution Control Act, as amended. Approval of the method of disposal of drill cuttings, sand, and other well solids shall be obtained from the District Supervisor.

1.2.2 *Containers.* Containers and other similar solid waste materials shall not be disposed of into the ocean.

1.2.3 *Equipment.* Disposal of equipment into the ocean is prohibited except under emergency conditions. The location and description of equipment disposed of into OCS waters shall be reported to the U.S. Coast Guard in accordance with paragraph 4 of OCS Order No. 1.

2. *Personnel, Inspections, and Reports.*

2.1 *Personnel.* The lessee's personnel shall be instructed in the techniques of equipment maintenance and operation for the prevention of pollution. Contractor personnel providing services offshore shall be informed in writing, prior to executing contracts, of the lessee's obligations to prevent pollution and of the provisions of this Order.

2.2 *Pollution Inspections.*

2.2.1 *Manned Facilities.* Manned drilling and production facilities shall be inspected daily to determine if pollution is occurring. Maintenance or repairs which are necessary to prevent pollution of the ocean waters shall be undertaken and performed immediately.

2.2.2 *Unattended Facilities.* Unattended facilities, including those equipped with remote control and monitoring systems, shall be inspected daily or at intervals prescribed by the District Supervisor to determine if pollution is occurring. Daily inspections may be postponed in the event of adverse weather conditions. Necessary maintenance or repairs shall be made immediately.

2.3 *Pollution Reports.* All spills of oil and liquid pollutants shall be reported orally to the District Supervisor and shall be confirmed in writing. All reports shall include the cause, location volume of spill, and action taken. Reports of spills of more than 5.0 cubic meters (31.5 barrels) shall include information on the sea state, meteorological conditions, size, and appearance of slick. All spills of oil and liquid pollutants shall also be reported to the U.S. Coast Guard in accordance with the procedures contained in 33 CFR 135.305 and 135.307.

2.3.1 *Spills.* Spills shall be reported orally within the following time limits:

a. Within 12 hours, if spills are 1.0 cubic meter (6.3 barrels) or less.

b. Without delay, if spills are more than 1.0 cubic meter (6.3 barrels).

2.3.2 *Observed Malfunctions.* Lessees shall notify each other observed pollution resulting from another's operation.

3. *Pollution-Control Equipment and Materials and Oil Spill Contingency Plans.* The lessee shall submit a description of procedures, personnel, and equipment that will be used in reporting, cleanup, and prevention of the spread of any pollution resulting from an

oil spill which might occur during exploration or development activities. The following subparagraphs describe the minimum requirements for pollution-control equipment and procedures.

3.1 *Equipment and Materials.* Pollution-control equipment and materials shall be maintained by, or shall be available to, each lessee at an offshore location or at a location approved by the Deputy Conservation Manager (DCM), Offshore Field Operations. The equipment shall include containment booms, skimming apparatus, cleanup materials, chemcial agents and other items needed for the existing climatic conditions, and shall be available prior to the commencement of drilling and production operations. The equipment and materials shall be inspected monthly and maintained in a state of readiness for use. The results of the inspections shall be recorded and maintained at the site.

3.2 *Oil Spill Contigency Plans.* The lessee shall submit an Oil Spill Contingency Plan for approval by the DCM, Offshore Field Operations, with or prior to submitting an Exploration Plan or a Development and Production Plan. Oil Spill Contingency Plans shall be reviewed annually. All modifications of the Oil Spill Contigency Plan and the results from the review of the plan shall be submitted to the DCM, Offshore Field Operations, for approval. The Oil Spill Contigency Plan shall contain the following:

a. Provisions to assure that full resource capability is known and can be committed during an oil spill, including the identification and inventory of applicable equipment, materials, and supplies which are available locally and regionally, both committed and uncommitted, and the time required for deployment of the equipment.

b. Provisions for varying degrees of response effort depending on the severity of the oil spill.

c. Provisions for identifying and protecting areas of special biological sensitivity.

d. Establishment of procedures for the purpose of early detection and timely notification of an oil spill including a current list of names, telephone numbers, and addresses of the responsible persons and alternates on call to receive notification of an oil spill, and the names, telephone numbers, and addresses of regulatory organizations and agencies to be notified when an oil spill is discovered.

e. Provisions for well-defined and specific actions to be taken after discovery and notifiation of an oil spill, including:

(1) Specification of an oil spill response operating team consisting of trained, prepared, and available operating personnel.

(2) Predesignation of an oil spill response coordinator who is charged with the responsibility and is delegated commensurate authority for directing and coordinating response operations.

(3) A preplanned location for an oil spill response operations center and a reliable communications system for directing the coordinated overall response operations.

(4) Provisions for disposal of recovered spill materials.

4. *Drills and Training.*

4.1 *Drills.* Drills for familiarization with pollution-control equipment and operational procedures shall be the lessee's responsibility and shall be held at least once every 12 months by the lessee or a contractor serving the lessee. The personnel identified as the oil spill response operating team in the Contingency Plan shall participate in these drills. The drills shall be realistics and shall include deployment of equipment. A time schedule with a list of equipment to be deployed shall be submitted to the DCM, Offshore Field Operations, for approval. The drill schedule shall provide sufficient advance notice to allow U.S. Geological Survey personnel to witness any of the drills. Drills shall be recorded, and the records shall be made available to U.S. Geological Survey personnel. Where drill performance and results are deemed inadequate, the DCM, Offshore Field Operations, may require an increase in the frequency or a change in the location of the drills until satisfactory results are achieved.

4.2 *Training.* The lessee shall ensure that training classes for familiarization with pollution-control equipment and operational procedures are provided for the oil spill response operating team. The supervisory personnel responsible for directing the oil spill response operations shall receive oil spill control instruction suitable for all seasons. The lessee shall retain course completion certificates or attendance records issued by the organization where the instruction was provided. These records shall be available to any authorized representative of the U.S. Geological Survey upon request.

5. *Spill Control and Removal.* Immediate corrective action shall be taken in all cases where pollution has occurred. Corrective action taken under the lessee's Oil Spill Contingency Plan shall be subject to modification when directed by the DCM, Offshore Field Operations. The primary jurisdiction to require corrective action to abate the source of pollution shall remain with the DCM, Offshore Field Operations, pursuant to the provisions of this Order and the Memorandum of Understanding (MOU) between the Department of Transportation (U.S. Coast Guard) and the Department of the Interior (U.S. Geological Survey), dated August 16, 1971. The use of chemical agents or other additives shall be permitted only after approval by the DCM, Offshore Field Operations, in accordance with Annex X, National Oil and Hazardous Substances Pollution Contingency Plan, and in accordance with the previously mentioned MOU.

6. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

U.S. Department of the Interior, Geological Survey Conservation Division

Alaska Region, Arctic—OCS Order No. 9

Effective ————

Platforms and Structures

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10 and 30 CFR 250.11 and in accordance with 30 CFR 250.18.

1. Applicability.

1.1 *New Platforms.* Subsequent to the effective date of this Order, all new fixed or bottom-founded platforms or other structures (e.g., single-pile caissons, ice islands, and gravel islands) shall be designed, fabricated, and installed in accordance with the applicable provisions of the document, entitled "Requirements for Verifying the Structural Integrity of OCS Platforms," and shall require approval under the provisions of this Order.

Where doubt exists as to the applicability of this Order, questions shall be referred to the Deputy Conservation Manager (DCM), Offshore Field Operations.

1.2 *Major Modifications and Repairs.* Subsequent to the effective date of this Order, major modifications and repairs of damage to all fixed or bottom-founded platforms or other structures shall require approval by the DCM, Offshore Field Operations. Major modifications are defined as any structural change which materially

alters the original plan or any major deviation from operations. Major repairs or damage are defined as operations involving members affecting the structural integrity of a portion of or all of the platform or other structure.

Repairs to primary structural elements may be made to restore an existing permitted condition without prior approval under emergency conditions. The DCM, Offshore Field Operations, shall be notified within 24 hours of the damage and subsequent repairs, and approval shall be obtained.

Where doubt exists as to the applicability of this Order, questions shall be referred to the DCM, Offshore Field Operations.

1.3 *Platform Verification.* All new platforms or other structures, and major modifications to platforms or other structures, shall be subject to review under the requirements of the Platform Verification Program and to the approval of the DCM, Offshore Field Operations.

1.4 *References.* Other aspects of the Platform Verification Program are described in more detail in the following documents, and these documents shall be considered as references for this Order.

1.4.1 *Operating Procedures for the OCS Platform Verification Program.* The document, entitled "Operating Procedures for the OCS Platform Verification Program," October 1979, describes the elements of the Platform Verification Program, the verification steps, the function of the Platform Verification Section, and the procedures for resolution of disputes; defines standards which shall be met by individuals or organizations in order to be approved as Certified Verification Agents (CVA); and provides instructions to the CVA.

1.4.2 *Requirements for Verifying the Structural Integrity of OCS Platforms.* The document, entitled "Requirements for Verifying the Structural Integrity of OCS Platforms," October 1979, is identified in this Order as "Requirements." It identifies mandatory state-of-the-art performance standards which shall be met in designing, fabricating, and installing platforms or other structures and major modifications to platforms or other structures.

1.4.3 *Appendices to Requirements for Verifying the Structural Integrity of OCS Platforms.* The document, entitled "Appendices to Requirements for Verifying the Structural Integrity of OCS Platforms," October 1979, is identified in this Order as "Appendices." It identifies alternative engineering design procedures which may be utilized, where applicable, to conform to the "Requirements."

1.4.4 *Commentary on Requirements for Verifying the Structural Integrity of OCS Platforms.* The document, entitled "Commentary on Requirements for Verifying the Structural Integrity of OCS Platforms," October 1979, is identified in this Order as "Commentary." It provides an explanation of the basic intent of the "Requirements" and also discusses the "Requirements," the "Appendices," and the current relative development of the state of practice for pertinent parts of both.

2. Responsibility

2.1 *Submission.* All applications for approval under the provisions of this Order shall be submitted to the DCM, Offshore Field Operations. All significant changes or modifications (i.e., any structural change which materially alters the original plans or any major deviation from operations) to approved applications shall be submitted for approval to the DCM, Offshore Field Operations. The lessee assumes risk of making changes or modifications without prior approval of the DCM, Offshore Field Operations. Where doubt exists as to whether a change is significant, questions shall be referred to the DCM, Offshore Field Operations.

2.2 *Certification.* The lessee shall have detailed structural plans and specifications for new platforms or other structures and major modifications certified by a registered professional structural engineer or civil engineer specializing in structural design. The lessee shall also sign and date the following certification:

(Lessee) certifies that the design of the (structure/modification) has been certified by a registered professional structural engineer or a civil engineer specializing in structural design, and the (structure/modification) will be fabricated, installed, and maintained as described in the application and any approved modification thereto. Certified design and as-built plans and specifications will be on file at ————.

2.3 *Verification.* The lessee shall nominate a CVA(s) in the verification plan and have the design, fabrication, and installation of all platforms or other structures and modifications to platforms or other structures which are subject to review under the requirements of the Platform Verification Program, verified by a CVA(s).

2.4 *Approval.* For new platforms or other structures and major modifications thereto subject to review under the requirements of the Platform Verification Program, the lessee shall obtain approval for the design and fabrication from the DCM, Offshore Field Operations, prior to transporting the platform or other structure to the installation site.

2.5 *Notification.* The lessee shall be responsibile for notifying the DCM, Offshore Field Operations, at least 1 week prior to transporting the platform or other structure to the installation site.

3. Submission.

3.1 *General.* The lessee shall submit to the DCM, Offshore Field Operations, in triplicate, all documentation necessary for approval of new platforms or other structures and major modifications in accordance with the provisions of this Order. Listed hereafter is the documentation which shall be submitted; however, more detailed information and data may be required on a case-by-case basis and upon specific request by the DCM, Offshore Field Operations.

3.2 Design

3.2.1 *Design Documentation.* The lessee shall submit design documentation with or subsequent to the submittal of the Exploration Plan or the Development and Production Plan. The design documentation shall include design drawings and material specifications for primary load-bearing members included in the space frame analysis, the certification by the lessee, and the name of the registered professional engineer. In addition, the design documentation shall incorporate the following:

a. General platform information.

b. Environmental and loading information.

c. Foundation information.

d. Structural information.

3.2.1.1 *General Platform Information.* The general platform information shall include the following:

a. Identification data including the platform or structure designation, the lease number, the area name, the block number, and the lessee's name.

b. Location data consisting of longitude and latitude coordinates, Universal Transverse Mercator grid system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection system, and a plat drawn to a scale of 1 centimeter=240 meters (1 inch=2,000 feet) showing surface location and distance from the nearest lease lines.

c. Intended primary use and other intended functions such as planned drilling, production, processing, well protection, compression, pumping or storage facility, or other operations.

d. Personnel facilities, personnel access to living quarters, number and

location of boat landings, heliports, cranes, and evacuation routes.

e. Platform or structure details which consist of drawings, plats, front and side elevations of the entire structure, and plan views that clearly illustrate the following: essential parts (i.e., equipment arrangement, number and location of well slots); design loadings of each deck; water depth; nominal size and thickness of all primary load-bearing jacket and deck structural members; nominal size, makeup, thickness, and design penetration of piling.

f. Corrosion protection or durability details which consist of the corrosion-protection method; expected life; and durability criteria for the submerged, splash, and atmospheric zones.

3.2.1.2 *Environmental and Loading Information.* The environmental and loading information shall include the following:

a. Environmental data, which consist of a summary listing of data, as addressed in the "Requirements," that have a bearing on the design, installation, and operation (e.g., wave heights and periods, current, vertical distribution of wind and gust velocities, water depth, storm and astronomical tide data, marine growth, snow and ice effects, and air and sea temperatures).

b. Derived loads which consist of a listing of total design functional loads and loads due to wind, wave, ice, and current forces for longitudinal, transversal, and diagonal approaches.

3.2.1.3 *Foundation Information.* The foundation information shall include the following:

a. Seabed testing results which consist of a brief summary of the major strata encountered at the location of the boring(s) presented in tabular form, a detailed subsurface profile illustrating results of field and laboratory testing, a listing of field and laboratory investigations and tests with a basic summary of resultant determinations, the identification of properties and conditions of the seabed and the subsoil, and the identification of any manmade hazards or obstructions.

b. Load effects which consist of a description of the effect of the environmental and functional loads on the foundation.

c. A soil stability report including a determination, with supporting information, of the susceptibility or non-susceptibility of the area to soil movement and, if susceptible to soil movement, an analysis of slope and soil stability.

d. Foundation design criteria which consist of a summary of the design criteria as specified in the "Requirements."

e. Seafloor survey results which consist of a summary of the survey specified in the "Requirements."

3.2.1.4 *Structural Information.* The structural information shall include the following:

a. Design life criteria which consist of the identification of the basis of the design life of the structure.

b. Design loading and criteria which consist of a summary description of the design load conditions and design load combinations taking into consideration the worst environmental and operational conditions anticipated over the service life of the plate form or structure.

c. Material specifications which consist of a listing and description of the appropriate specifications.

d. Design strength criteria which consist of a description of the method(s) used in design (i.e., elastic, plastic ductility, ultimate).

e. Fatigue assessment details which consist of a summary of the fatigue analysis as specified in the "Requirements." The requirement for fatigue analysis shall be determined on a case-by-case basis. Where doubt exists concerning the requirement for this analysis, questions shall be referred to the DCM, Offshore Field Operations.

3.2.2 *Design Verification Plan.* For new platforms or other structures, and for modifications which are subject to review under the requirements of the Platform Verification Program, the lessee shall submit a design verification plan with or subsequent to the submittal of the Development and Production Plan. The verification plan shall include a short summary which nominates the CVA, states the qualifications of the CVA, describes how the lessee intends to use the CVA, identifies the level of work to be performed by the CVA, and identifies the documents which will be furnished with the platform application. Furthermore, the documentation listed under 3.2.1, as well as computer program descriptions which consist of abstracts of the computer programs used or to be used in various phases of the design process, shall be submitted as a part of the design verification plan.

The design verification plan shall be resubmitted for approval if the CVA changes, if the CVA's qualifications change, or if the level of work to be performed by the CVA changes. However, the summary of technical details need not be resubmitted unless changes are made in the technical details.

3.3 *Fabrication.* For new platforms or other structures and for modifications which are subject to review under the requirements of the Platform Verification Program, the lessee shall submit a fabrication verification plan subsequent to the submittal of the design. The plan shall include a short summary which nominates the CVA, states the qualifications of the CVA, describes how the lessee intends to use the CVA, identifies the level of work to be performed by the CVA, and identifies the documents which will be furnished to the CVA. The plan shall include fabrication drawings and material specifications of all the primary load-bearing members included in the space-frame analysis and a summary description of the following:

a. Structural tolerances.

b. Welding procedures.

c. Fabrication standards.

d. Material quality-control procedures.

e. Methods and extent of Nondestructive Examinations (NDE) for welds and materials.

f. Quality assurance procedures.

The fabrication verification plan shall be resubmitted for approval if the CVA changes, if the CVA's qualifications change, or if the level of work to be performed by the CVA changes. However, the summary of technical details need not be resubmitted unless changes are made in the technical details.

3.4 *Installation.* For new platforms or other structures and for modifications subject to review under the requirements of the Platform Verification Program, the lessee shall submit an installation verification plan subsequent to the submittal of the fabrication verification plan. The plan shall include a short summary which nominates the CVA, states the qualifications of the CVA, describes how the lessee intends to use the CVA, identifies the level of work to be performed by the CVA, and identifies the documents which will be furnished to the CVA. The plan shall also include a summary description of the planned marine operations, contingencies considered, alternate courses of action, and a summary description of the inspections to be performed during marine operations, including a graphical identification of areas to be inspected and acceptance/rejection criterion. The installation verification plan shall be resubmitted for approval if the CVA changes, if the CVA's qualifications change, or if the level of work to be performed by the CVA changes. However, the summary of technical details need not be resubmitted unless changes are made in the technical details.

For structures fabricated and installed in place (e.g., ice islands and gravel islands), the fabrication and installation verification plans may be combined.

4. *Records.* The lessee shall compile, retain, and make available for review for the functional life of the platform or other structure that is subject to the provisions of this Order, the as-built structural drawings, the design assumptions and analysis, and a summary of the NDE records.

5. *Departures.* All departures from the requirements specified in this Order shall be subject to approval pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Field Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulation.

U.S. Department of the Interior, Geological Survey Conservation Division

Alaska Region, Arctic

OCS Order No. 12

Effective ————

Public Inspection of Records

This Order is issued pursuant to the authority prescribed in 30 CFR 250.10, 250.11, and in accordance with 30 CFR 250.3, 250.34, 252.6, and 43 CFR Part 2. Requests for information made under the Freedom of Information Act, 5 U.S.C. § 552, will be governed by the provisions of 43 CFR Part 2 (40 FR 7304, February 19, 1975).

1. *Filing of Reports.* All reports on Forms 9–152, 9–330, 9–331, 9–331 C, 9–1869, 9–1870, and the forms used to report the results of multipoint back-pressure tests shall be filed by the lessee in accordance with the following:

a. All reports submitted on these forms shall include a copy with the words "Public Information" shown on the lower right-hand corner. This copy of the form shall be made available for public inspection.

b. All items on the form not marked "Public Information" shall be completed in full, and such forms and all attachments thereto shall not be available for public inspection.

c. The copy marked "Public Information" shall be completed in full except that the items described in subparagraphs 2.1 through 2.4 below, and the attachments relating to such items, may be excluded.

2. *Availability of Records.* The following records pertaining to leases wells in the Outer Continental Shelf (OCS) and submitted under 30 CFR 250 shall be made available for public inspection, as specified below, in the Regional Office:

2.1 *Form 9–152—Monthly Report of Operations.* All information contained on this form shall be available except proprietary information which may be included in the remarks column. The lessee shall delete such proprietary data from the public information copy.

2.2 *Form 9–330—Well-Completion or Recompletion Report and Log.*

2.2.1 *Prior to Commencement.* Prior to commencement of production, all information contained on this form shall be available except:

a. Item 1a, Type of Well.

b. Item 4, Location of Well, at top production interval and at total depth.

c. Item 22, If Multiple Completion, how many.

d. Item 24, Producing Interval.

e. Item 26, Type Electric and Other Logs Run.

f. Item 28, Casing Record.

g. Item 29, Liner Record.

h. Item 30, Tubing Record.

i. Item 31, Perforation Record.

j. Item 32, Acid, Shot, Fracture, Cement Squeeze, Etc.

k. Item 33, Production.

l. Item 37, Summary of Porous Zones.

m. Item 38, Geologic Markers.

2.2.2 *After Commencement of Production.* After commencement of production, all information shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers.

2.2.3 *5 Years' Elapsed Time.* If production has not commenced after an elapsed time of 5 years from the date of filing Form 9–330 as required in 30 CFR 250.38(b), excluding the total time that operations and production are suspended by direction of the Secretary of the Interior, or his duly authorized representative, and further excluding the total time that operations and production are stopped or prohibited by Court Order, all information contained on this form shall be available except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers. Within 90 days prior to the end of the 5-year period, exclusive of exceptions noted above, the lessee shall file a Form 9–330 containing all information requested on the form except Item 37, Summary of Porous Zones, and Item 38, Geologic Markers, to be made available for public inspection. Objections to the release of such information may be submitted with the completed Form 9–330.

2.3 *Form 9–331—Sundry Notices and Reports on Wells.*

2.3.1 *"Request for Approval to."* When used as a "Request for Approval to" conduct operations, all information contained on this form shall be available except Item 4, Location of Well, at top production interval and at total depth, and Item 17, Described Proposed or Completed Operations.

2.3.2 *"Subsequent Report of."* When used as a "Subsequent Report of" operations, and after commencement of production, all information contained in this form shall be available, except information contained in Item 17 pertaining to subsurface locations and measured and true vertical depths for all markers and zones not placed on production.

2.4 *Form 9–331 C—Application for Permit to Drill, Deepen, or Plug Back.* All information contained on this form and the location plat attached thereto shall be available except Item 4, Location of Well at Proposed Production Zone, and Item 23, Proposed Casing and Cementing Program.

2.5 *Form 9–1869—Quarterly Oil Well Test Report.* All information contained on this form shall be available.

2.6 *Form 9–1870—Semiannual Gas Well Test Report.* All information contained on this form shall be available.

2.7 *Multipoint Back Pressure Test Report.* All information contained in this report shall be available.

2.8 *Sales of Lease Production.* Information contained on the monthly U.S. Geological Survey computer printout showing sales volumes, value, and royalty on production of oil, condensate, gas, and liquid products by lease shall be made available.

2.9 *Availability of Inspection Records.* All accident-investigation reports, pollution-incident reports, facilities-inspection data, and records of enforcement actions are also available for public inspection.

2.10 *Availability of Data and Information Submitted by Lessees.* Certain inormation submitted by lessees, as a result of OCS Orders and OCS Notices to Lessees and Operators, is nonproprietary in nature, or release of such information is necessary for the proper development of the lease. This information will be made available for public inspection, except for those portions which the lessee shall designate, with the approval of the Deputy Conservation Manager (DCM), Offshore Field Operations, as trade secrets and commercial or financial information which is privileged or confidential. The available information will include:

a. Notice of support activity.

b. Oceanographic and meteorological data collected from drilling units and

production facilities during the period of operations.

c. Results of site surveys required prior to drilling or placement of platforms or structures, such as shallow geologic hazards surveys, archaeological/cultural resource surveys, or other surveys related to the placement of platforms or structures.

d. Drawings, maximum environmental design criteria, and rated capability data of mobile drilling units and structures.

e. Oil Spill Contingency Plans.

f. Critical Operations and Curtailment Plans.

g. Other data required under 30 CFR 250.34.

2.11 T3Expired Leases. All information is available upon the expiration of a lease.

3. *Information Exempt from Public Inspection.* The information in subparagraphs 2.1 through 2.4 which has been restricted from public inspection is classified as geological and geophysical data. Except as provided in 30 CFR 250.3, 250.4, and 252.7, the release of this data is subject to the following restrictions:

3.1 T3Leases Issued Prior to June 11, 1976. For leases issued prior to June 11, 1976, the classified data is exempt from disclosure under exemption No. (9) of the Freedom of Information Act (5 U.S.C. 552(b)(9) and 43 CFR 2.13 subsection (c), *Statutory Exemptions,* (9)).

3.2 T3Leases Issued After June 11, 1976. For leases issued after June 11, 1976, the classified data is available in accordance with 30 CFR 250.3, *Data and information to be made available to the public,* as follows:

a. Geophysical data, processed geophysical information, and interpreted geological and geophysical information shall not be available for public inspection, except as provided in 2.10c, without consent of the lessee as long as the lease remains in effect or for a period of 10 years after the date of submission, whichever is less, unless the DCM, Offshore Field Operations, with the approval of the Director, determines that earlier release of this information is necessary for proper development of the field or area.

b. Geological data and analyzed geological information shall not be made available for public inspection without the consent of the lessee as long as the lease remains in effect or for a period of 2 years after the date of submission, whichever is less, unless the DCM, Offshore Field Operations, with the approval of the Director, determines that earlier release of such information is necessary for the proper development of the field or area. In accordance with 30 CFR 250.38, *Well Records* data and well records shall be transmitted to the DCM, Offshore Field Operations, upon request or, if not requested, within 30 days following completion of suspension of any well. For the purpose of orderly release of data, in all cases the date of submission will be considered to be 30 days following such completion or suspension.

4. *Departures.* All departures from the requirements specified in this Order shall be subject to approval, pursuant to 30 CFR 250.11(b).

Rodney A. Smith,

Deputy Conservation Manager, Offshore Fields Operations.

Approved:

Robert L. Rioux,

Deputy Chief, Conservation Division—Offshore Minerals Regulations.

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